

BEFORE THE ~~Arizona Public Service~~ ARIZONA PUBLIC SERVICE CORPORATION COMMISSION

DOCKETED

JUN 01 1994

MARCIA WEEKS

CHAIRMAN

RENZ D. JENNINGS

COMMISSIONER

DALE H. MORGAN

COMMISSIONER

DOCKETED BY

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IN THE MATTER OF THE A.A.C.
R14-2-704 HEARING FOR INTEGRATED
RESOURCE PLANNING.

DOCKET NO. U-0000-93-052

DECISION NO. 58643

OPINION AND ORDER

DATES OF HEARING:

August 20 and November 22, 1993 (Procedural
Conferences), December 7, 8, 9, 10, 13 and
14, 1993

PLACE OF HEARING:

Phoenix, Arizona

PRESIDING OFFICER:

Bradley S. Carroll

IN ATTENDANCE:

Renz D. Jennings, Commissioner
Dale H. Morgan, Commissioner

APPEARANCES:

SNELL & WILMER, by Mr. Thomas L. Mumaw, and
Arizona Public Service Legal Department, by
Ms. Vicki G. Sandler, on behalf of Arizona
Public Service Company;

Mr. David Lamoreaux and Mr. Steven J.
Glaser, Tucson Electric Power Company Legal
Department, on behalf of Tucson Electric
Power Company;

Mr. Craig A. Marks, Senior Counsel, on
behalf of Citizens Utilities Company;

JOHNSTON, MAYNARD, GRANT & PARKER, by Mr.
Michael M. Grant, on behalf of the Arizona
Electric Power Cooperative;

Ms. Diane Evans, Salt River Project Law
Department, on behalf of Intervenor Salt
River Project Agricultural Improvement and
Power District;

Mr. Andrew W. Bettwy, Associate General
Counsel on behalf of Intervenor Southwest
Gas Corporation;

MEYER, HENDRICKS, VICTOR, OSBORN & MALEDON,
by Mr. Bruce E. Meyerson, on behalf of
Intervenor Arizona Community Action
Association;

BROWN & BAIN, P.A., by Mr. Lex J. Smith on behalf of Intervenor Phelps Dodge Corporation;

Mr. Bruce Driver and Mr. Eric Blank, on behalf of Intervenor Land & Water Fund of the Rockies;

Steve Brittle, President, on behalf of Intervenor Don't Waste Arizona, Inc.;

ELLIS, BAKER & PORTER, LTD., by Mr. Richard L. Sallquist, on behalf of Intervenor Cyprus Mineral Company;

Mr. Lothar M. Schmidt, Intervenor in Propria Persona;

Mr. K. Justin Reidhead, Chief Counsel, on behalf of the Residential Utility Consumer Office; and

Mr. Bradford A. Borman and Ms. Janice M. Alward, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

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1 BY THE COMMISSION:

2 PROCEDURAL HISTORY

3 Pursuant to A.A.C. R14-2-703.F, Arizona Public Service Company
4 ("APS"), Tucson Electric Power Company ("TEP"), Arizona Electric Power
5 Cooperative ("AEPCO"), and Citizens Utilities Company ("Citizens"),
6 filed with the Arizona Corporation Commission ("Commission") their
7 respective resource plans and related exhibits (collectively referred
8 to herein as "Plans"). APS and TEP filed their Plans on December 31,
9 1992, AEPCO filed its Plan on February 16, 1993, and Citizens filed
10 its Plan on March 31, 1993. Additionally, on January 29, 1993, Salt
11 River Project Agricultural Improvement and Power District ("SRP")
12 voluntarily filed a Plan. On March 24, 1993, pursuant to A.A.C. R14-
13 2-704.A, the Commission issued Decision No. 58227 which, in part,
14 ordered that a hearing for resource planning be scheduled to commence
15 on or after December 6, 1993. By Procedural Order dated April 12,
16 1993, the hearing was set to commence on December 7, 1993.

17 The following parties applied for, and were granted intervention:
18 the Residential Utility Consumer Office ("RUCO"), Southwest Gas
19 Corporation ("SWG"), SRP, Land and Water Fund of the Rockies ("LAW
20 Fund"), Mr. Lothar M. Schmidt, Arizona Community Action, ("ACAA"),
21 Phelps Dodge Corporation, Don't Waste Arizona, Inc.¹, and Cyprus
22 Minerals Company.

23 Workshops related to this Docket were held on October 8, 18, 19
24 and 20, 1993 and the hearing commenced on December 7, 1993 before a
25 duly authorized Hearing Officer of the Commission at the Commission's
26 offices in Phoenix, Arizona. At the beginning of the hearing, public
27

28 ¹ For this proceeding, Don't Waste Arizona, Inc.'s interests
were represented by the LAW Fund.

comment was taken. The hearing was conducted along the following topical lines: load forecasting; administrative matters; demand side management; and supply side issues. At the conclusion of the hearing, the Hearing Officer took the matter under advisement pending submission of a Recommended Opinion and Order to the Commission and the parties were given leave to file closing memoranda in lieu of closing statements.

DISCUSSION

I. Introduction

On October 14, 1988, the Commission issued Decision No. 56180 which adopted rules to implement Integrated Resource Planning ("IRP") in the State of Arizona. On January 12, 1989, the Commission issued Decision No. 56313 which amended the IRP rules. These rules require electric utilities with generating facilities to submit Plans every three years. Pursuant to A.A.C. R14-2-704, the Commission is to determine the degree of consistency between the Plans filed by the utilities and the analysis conducted by Staff, as well as the information provided by other parties. In making its consistency determination, the Commission is to consider, among other things, the following:

- ♦ the total cost of electric energy services;
- ♦ the degree to which the factors which affect demand, including demand management, have been taken into account;
- ♦ the degree to which non-utility supply alternatives, such as cogeneration and self-generation, have been taken into account;
- ♦ uncertainty in demand and supply analyses, forecasts, and plans, and the flexibility of plans enabling response to unforeseen changes in supply and demand factors; and
- ♦ the reliability of power supplies.

1 Pursuant to the rules, APS, TEP, AEPCO, and Citizens (collectively
2 referred to hereinafter as the "Companies"), filed with the Commission
3 their respective Plans. Additionally, SRP voluntarily filed a Plan.

4 The purpose of the IRP process is to minimize the total societal
5 costs of meeting the demand for electric energy services giving due
6 consideration to ratepayer impacts, global competitiveness, utility
7 financial health and economic growth within a utility's service area.
8 This goal can be achieved by finding the mix of supply and demand side
9 resources that minimizes society's costs. Electric utilities,
10 however, are coming under increasing competitive pressure to keep
11 prices to their customers low. Impacts on the competitive position of
12 Arizona's utilities warrant specific consideration in the development
13 and implementation of IRPs. The competitive position of U.S. business
14 in the global marketplace also warrants consideration. This
15 competitiveness depends, in part, on energy efficiency.
16 Notwithstanding the competitive pressures in Arizona, the U.S., and
17 the global marketplace, short-term competitive pressures should not
18 overwhelm the long-term need to have a balanced portfolio of supply
19 and demand resources.

20 One of Staff's roles in the IRP process is to review the Plans
21 filed by the Companies for consistency under the Commission's rules.
22 Staff conducts its own load forecasts, examines demand side resources,
23 and evaluates alternative supply side resources over the life cycle of
24 the resources, including the comparison of renewable resource
25 technologies with conventional fossil fuel resources. Staff also
26 reviews utility system reliability. The analysis of environmental
27 externalities has not yet begun, but Staff is developing rules based
28

the recommendations of an externalities task force report prepared during 1992 as a result of the last IRP docket.

II. Demand Side Management

Introduction

Demand side management ("DSM") is the systematic effort to improve the efficiency of using electric energy and power. Examples of DSM are energy efficient lighting, improved building thermal envelopes, reduced standby loss in water heaters, and more efficient electric motors. DSM is cost-effective if reductions in power usage at peak production times for the utility and reductions in energy usage at any time are less costly to society than generating, transmitting, and distributing electricity, including building of any new generation, transmission, or distribution capacity.

The Law Fund² has posited three regulatory elements that are necessary to encourage utilities to invest in cost-effective energy efficient programs:

- ♦ utility recovery of the costs it incurs to plan, design, implement, and evaluate its DSM programs;
- ♦ recovery of the lost net revenue caused by the energy and demand reductions attributed to the utility's DSM programs; and
- ♦ a financial incentive for the utility to encourage it to run innovative and aggressive DSM programs.

The major DSM programs currently underway in Arizona are:

- ♦ commercial sector lighting programs in which inefficient lighting is replaced by more efficient lamps and ballasts, in which adequate lighting levels are maintained through delamping and installation of reflectors, and in which lighting is controlled by occupancy sensors and dimmers;

² The LAW Fund is a regional environmental organization headquartered in Boulder, Colorado with its membership drawn from the Rocky Mountain and Desert Southwest states. The Energy Project of the LAW Fund is committed to reducing the environmental impacts associated with meeting the need for utility energy services.

- 1 ♦ educational programs aimed primarily at school children;
- 2 ♦ new home programs aimed at meeting energy-efficient mortgage
- 3 performance standards for the entire house allowing builders
- 4 to substitute among efficiency measures to meet the
- 5 standard;
- 6 ♦ residential retrofit programs, currently focused on
- 7 upgrading the efficiency of heat pumps;
- 8 ♦ residential audits including audits by mail and on-site
- 9 audits;
- 10 ♦ tree planting to create shade on sunstruck sides of
- 11 buildings thereby reducing space cooling needs; and
- 12 ♦ replacement of existing motors with energy efficient motors.

13 The Commission currently has a process for reviewing utility DSM
14 programs in cases where the Commission has established a cost-recovery
15 mechanism. In particular, in order to qualify for cost recovery,
16 Staff must pre-approve each utility program before it is implemented.
17 Staff's pre-approval review looks at societal costs and benefits,
18 program feasibility, the marketing plan, and the monitoring and
19 evaluation plan.

20 Proposed Type and Level of DSM

21 In general, the range of DSM programs is expected to expand from
22 current efforts. Utility projections of DSM power savings are about
23 1160 megawatts ("MW") between 1992 and 2010. Overall, through 2010,
24 additions of DSM are about one quarter of the projected growth in
25 demand (where demand consists of retail demand plus energy services
26 met through DSM.)

27 At the hearing, the Companies summarized their DSM goals for the
28 present and future. APS indicated that DSM expenditures should not be
mandated as a simple proportion of gross revenue. Instead, APS
believes that DSM should be pursued to achieve the highest benefit at
the lowest cost.

1 TEP testified that its primary objectives for DSM are achieving
2 peak load reduction and obtaining load factor improvement, while
3 making cost beneficial resource decisions that minimize rate impacts.
4 The TEP 1992 Plan projects 100 MW of new DSM over the next 15 years in
5 addition to the 7 MW already achieved through 1992. TEP testified
6 that this accounts for 22 percent of all the expected resource
7 additions over this period and results in an overall peak reduction of
8 five percent. TEP estimates that annual energy reduction in the year
9 2007 will be approximately 330 gigawatt hours ("gwh"), representing an
10 overall energy reduction of 3.5 percent.

11 AEPCO testified that it is committed in the short-term to
12 implementing a variety of new DSM programs to complement its existing
13 DSM activities. AEPCO believes that the magnitude and timing of these
14 programs can be accelerated or scaled back in response to changing
15 economic, social, environmental, and regulatory conditions.
16 Additionally, AEPCO indicated that it can adjust the magnitude and
17 timing of its DSM programs based on feedback regarding the cost and
18 performance of these programs. AEPCO has already taken steps towards
19 implementing the DSM programs identified in its Plan. Its Marketing
20 Task Force has developed commercial lighting, industrial motor, and
21 energy storage programs that have been submitted (as of the date of
22 the hearing) to its Board of Directors for approval.

23 Many utility programs are technology specific (e.g., a lighting
24 program) and historically, utility programs have emphasized rebates to
25 induce customers to participate. In contrast, Citizens is proposing
26 facility-based programs to implement all cost-effective measures for
27 commercial, industrial, and residential participants. Citizens also
28 plans to use energy service companies ("ESCO") to implement many of

1 its programs and program participants will repay the ESCO for the DSM
2 measures out of their savings. Citizens is also placing a heavy
3 emphasis on using local organizations and trade allies to implement
4 programs rather than having the utility implement the programs.

5 — As a potential addition to the menu of DSM programs offered by
6 the Companies, Staff recommended that the Companies consider a design
7 team approach to new commercial buildings to encourage the
8 construction of energy efficient new buildings. As this
9 recommendation is meritorious and was unopposed, we shall direct the
10 Companies to either develop a design team approach to new commercial
11 buildings to encourage the construction of energy-efficient new
12 buildings, or indicate in their regular reports on DSM programs, why
13 design teams are not appropriate. Staff also recommended that the
14 Commission adopt as a general policy, a requirement that all special
15 contracts which offer discounted rates to attract a business or retain
16 a business include a provision mandating that the customer implement
17 energy efficiency measures if cost-effective to do so.

18 Staff believes that repayment programs in which program
19 participants repay the utility any incentives out of savings may be
20 successful in lowering the costs to the utility of implementing DSM
21 programs and more equitably distribute the costs of DSM programs in
22 relation to the benefits received. It is, however, currently
23 difficult to determine when success is likely. Staff has proposed
24 that it prepare a background paper based upon experience in other
25 jurisdictions and then conduct a workshop to discuss the paper and to
26 hear presentations by representatives from organizations with
27 experience in repayment programs. We believe that Staff's proposal
28 will educate the Companies and the Commission on repayment programs

and we will require Staff to undertake this workshop. The Companies, commercial and industrial customers, and residential consumer organizations should be invited to attend the workshop and should be prepared to discuss the advantages and disadvantages of repayment programs. The LAW Fund's bonus program should also be included as a topic in the workshop.

Several intervenors commented on proposed DSM programs. The LAW Fund raised concerns that the proposed DSM programs primarily reduce peak demand and may not reduce energy consumption and may even increase energy consumption. Staff believes that the major pre-approved DSM programs such as energy-efficient new homes, commercial lighting, efficient motors, and shade trees are likely to save significant amounts of energy and power.

ACAA³ presented evidence on the advantages of increased energy efficiency programs for Arizona which extend to low-income utility customers. ACAA indicated that the purpose of its testimony was to urge the Commission to:

- ♦ approve adequate and cost-effective DSM measures for all utility consumers with a fair and equitable portion of DSM resources devoted to low-income customers;
- ♦ establish a collaborative process for the development, implementation, evaluation, and monitoring of all DSM programs; and
- ♦ establish alternative DSM delivery mechanisms with specific measures such as lighting, refrigerator replacement, and tree planting.

ACAA believes that the proposed Plans and DSM program packages of both APS and TEP are positive and important steps towards realizing the economic and environmental benefits of IRP and that these companies

³ ACAA is a statewide private, non-profit organization whose primary concern is helping low-income people become self-sufficient. There are 22 community action programs throughout Arizona.

1 deserve credit for their good-faith efforts in developing their Plans
2 and programs to pursue energy efficiency as a cost-effective
3 alternative to conventional supply side resources. ACAA also believes
4 that both companies have established important foundations for
5 development of this alternative, and their efforts are not to be
6 discounted. ACAA, however, argued that all major customer classes,
7 regardless of size or type, should have an opportunity to participate
8 in a meaningful and substantive DSM program.

9 RUCO testified that the Plans fail to analyze the appropriate
10 issues or acknowledge that much of the information needed for
11 effective planning (particularly on the DSM portion of the Plan) is
12 simply not available at this time and needs to be systematically
13 acquired through actual experience from implementation of DSM
14 measures. RUCO indicated that while much hard work and good analysis
15 was performed by the various utility staffs and consultants, the Plans
16 that were filed (except Citizens') fail to provide a useful analysis
17 or plan for the future. RUCO requested that the Commission direct
18 that more measures and programs be screened for cost-effectiveness
19 under a variety of circumstances and conditions. Additionally, RUCO
20 stated that the Commission should direct that the methods used to
21 screen measures or programs, or to select program plans, be consistent
22 with the primary objectives identified by the Commission in its
23 integrated least cost planning process. Further, RUCO recommended, in
24 part, that the Companies should, in consultation with Staff and
25 interested parties, plan and undertake an aggressive effort to:

- 26 ♦ learn how to acquire large scale DSM resources successfully
27 and more cost-effectively, while attempting to minimize
28 potential rate impacts. The Companies should test market
preparation, market transformation, integrated delivery and
program designs in which the participants repay the utility
for conservation services on their utility bill;

- 1 ♦ promptly pursue the development and implementation of
2 effective low-income DSM programs by recognizing all of the
3 benefits available from such programs and by increasing the
4 cost-effectiveness of such programs by pursuing joint
5 delivery with other utilities and with weatherization
6 providers;
- 7 ♦ pursue the application of innovative and intensive DSM
8 efforts including the use of community-based demonstration
9 projects to try to avoid the need for new transmission
10 capacity in the Anza and Mohave regions.

11 RUCO also noted that the Commission should not establish a maximum
12 level of achievable DSM potential due to the current lack of
13 information and data to develop a credible estimate of such potential.
14 RUCO, however, believes that the Commission could accept for planning
15 purposes the proposed DSM resource potential estimates presented in
16 the Plans as reasonable at this time.

17 ACAA believes that the commitment to DSM as a viable, cost-
18 effective energy resource by both APS and TEP needs to be
19 significantly increased. ACAA found that the Companies' DSM budgets
20 and savings targets are low, and each Company's process to analyze,
21 develop and implement DSM programs could be improved to assure that
22 DSM as an energy resource is developed to its full potential. ACAA
23 has recommended that APS should have spending targets of between 2.5
24 percent and 5 percent of gross operating revenues for DSM. ACAA has
25 also proposed specific dollar levels for DSM programs, well in excess
26 of current levels, recommending an annual budget of \$35 to \$70 million
27 for APS and an annual budget of \$13 to \$26 million for TEP.

28 We agree that larger programs are desirable now that APS and TEP
29 have demonstrated their ability to develop, implement, review, and
30 modify DSM programs. DSM programs should be undertaken as long as the
31 incremental benefits to society exceed the incremental costs to
32 society. It is conceded that many utilities throughout the U.S. have

1 had a much larger commitment to DSM than TEP and APS. In 1989, DSM
2 spending for all U.S. utilities as a percentage of total electric
3 utility revenue was .5 percent; and in 1992, 1.2 percent. No Arizona
4 utility has achieved .5 percent yet. We intend to look at DSM levels
5 closely in rate cases.

6 At this time, there is, however, insufficient information to
7 determine whether ACAA's levels are appropriate and dollar targets
8 have the drawback of focusing on how fast to spend money rather than
9 how to achieve cost-effective savings. A dollar target can be
10 understood only if the types of DSM programs and delivery mechanisms
11 contemplated are known. Furthermore, it is wise to be cautious
12 concerning the start of too many programs simultaneously because
13 utility staffs may be unable to properly develop, implement, monitor,
14 and evaluate those programs.

15 We find that the Companies, especially TEP and APS, should
16 expeditiously increase their DSM activities and targets and that these
17 accelerated DSM targets should be included in the next IRP filings.
18 We will not adopt specific targets at this time as we believe that the
19 Companies should have the time and opportunity to first make their own
20 determinations. If, however, the Companies do not accelerate their
21 DSM activities, we shall reconsider specific targets in future IRP
22 hearings which also may include mandates for reaching such targets as
23 proposed by ACAA.⁴

24 ACAA also proposed specific budget levels for low-income DSM
25 programs of \$2.4 to \$4.8 million for APS and \$885,000 to \$1.77 million
26 for TEP. Further, both RUCO and the LAW Fund support the development
27

28 ⁴ Under this analysis, we will not order APS to implement
its IRP Plan 11 (as opposed to IRP Plan 10) as recommended by ACAA.

1 of more and better designed low-income DSM programs. We support cost-
2 effective DSM for low income households. The specific level, however,
3 will depend on the incremental societal costs and benefits of DSM for
4 low income households and the proper level of activity cannot be
5 determined without some actual experience. For example, ACAA
6 indicates that there are several possible barriers to improved energy-
7 efficiency in low-income housing units such as high hurdle rates, lack
8 of information, lack of capital, and rental status. We shall,
9 therefore, direct the Companies to develop their DSM programs to deal
10 with these kinds of problems.

11 APS has indicated that it supports a new DSM program for low-
12 income housing and is proposing to submit a specific design to Staff.
13 APS also indicated it would invite ACAA to work with it prior to final
14 design and submittal of the low-income plan. We encourage such
15 cooperation.

16 Although we will not adopt specific targets for low-income
17 programs at this time, we will direct APS to begin its low-income
18 pilot program with potentially cost-effective DSM measures and then,
19 after one year, modify the program as appropriate. TEP should use the
20 results of its current low-income program to develop a larger, cost-
21 effective low-income DSM program. We believe that DSM programs ought
22 to reflect an equitable division among all customers, including low-
23 income customers.

24 We also note that the magnitude of DSM activities will affect
25 utility rates. A precise estimate of the rate impacts of large
26 increases in expenditures for DSM for APS and TEP can only be
27 determined in the context of a rate case with details on DSM
28 expenditures, other utility costs, impacts of DSM on kilowatt ("kw")

1 and kilowatt hour ("kwh") sales, impacts of DSM on utility costs, rate
2 design parameters, and other factors.

3 ACAA has also recommended that the Companies should be directed
4 to consider fuel switching in its future resource mix. We concur with
5 this recommendation and will require the Companies to at least
6 consider in their next IRP filing, whether fuel switching as a DSM
7 resource potential is an option.

8 Public Input into DSM Programs

9 The Commission's IRP process offers the opportunity to provide
10 public input into the selection of DSM measures and design of DSM
11 programs. Parties to this Docket have provided important
12 recommendations on how to improve the menu of DSM programs offered by
13 the Companies.

14 The LAW Fund proposed a fund which would support participation by
15 intervenors in IRP activities. Although we believe that there are
16 some inherent problems with this, such as how to determine whether an
17 intervenor is given money from the fund, the LAW Fund is free to
18 explore this proposal with Staff and other parties at workshops to be
19 held in the future.

20 Southwest Gas Corporation ("Southwest Gas") is concerned that the
21 current process for review of electric utility IRP Plans is too
22 limited to allow adequate analysis and comment from all intervenors,
23 thereby unduly restricting input the Commission might otherwise be
24 provided. Southwest Gas is also concerned that the Companies may
25 disguise promotional programs as DSM programs. Southwest Gas
26 recommended that the Commission take steps to ensure that adequate
27 information is made public about each Plan to allow review by
28 intervenors and members of the public. It also recommended that an

1 annual reporting process for review of DSM activities should be
2 instituted. In that filing, the Companies should update the status of
3 each DSM program. The filing should then be docketed and be a part of
4 the public record. Finally, the Commission should carefully review
5 the DSM programs of APS to ensure that any promotional activities are
6 removed.

7 The Companies prepare regular reports for Staff on progress with
8 their DSM programs. It appears that some parties have not found these
9 reports easy to obtain and may have misconstrued the availability of
10 these reports. Southwest Gas states that utility DSM reports "have
11 been filed on a confidential basis and are not available for public
12 inspection." With some minor exceptions, no parts of any utility DSM
13 reports are confidential. Southwest Gas, however, has raised a valid
14 concern regarding availability of DSM reports and the ability of the
15 parties and the public to have more input into the DSM approval
16 process.

17 To make obtaining the reports easier, we shall require each
18 utility to file one copy of its DSM reports with the Commission's
19 Docket Control for better public access. We also believe that the
20 current procedure for Staff pre-approval of utility DSM programs for
21 which recovery is sought, does not permit sufficient opportunity for
22 interested parties (such as RUCO, competitors, and other intervenors)
23 to have direct input prior to Staff approval. Further, although
24 interested parties may have the opportunity to challenge the approval
25 at the utility's next general rate case by arguing that the program is
26 promotional or deleterious, we recognize that there is an inherent
27 unfairness due to the pre-approval itself, as well as a utility's
28 ability to do what Southwest Gas has termed as "distort the market."

1 Although we do not necessarily agree that there has been, or will be,
 2 a distortion of the market, we shall require any utility that files a
 3 DSM program for Staff pre-approval for recovery, to file a notice of
 4 such filing and a copy of such plan with the Commission's Docket
 5 Control and notify all interested parties⁵ of the filing. The
 6 interested parties shall then have 20 days to file any written
 7 comments with Staff so that Staff may take such comments into
 8 consideration before granting or denying pre-approval. Upon Staff's
 9 pre-approval, Staff should submit the projects to the Commission for
 10 its consideration and preliminary adoption. If the Commission adopts
 11 the pre-approval, the projects should be considered approved for cost-
 12 recovery in future rate proceedings. The Commission, however,
 13 reserves the right to review the projects in future rate proceedings,
 14 if necessary, to make a final determination with respect to the
 15 appropriateness of the cost-recovery.

16 The LAW Fund recommends that the Commission ask the Companies to
 17 establish a DSM collaborative process to prepare Plans to address
 18 three inter-related issues:

- 19 ♦ the scope of an expanded commitment to DSM;
- 20 ♦ changes in Commission regulation to encourage Arizona
 21 utilities to acquire all cost-effective DSM over the long-
 run; and
- 22 ♦ measures to address or mitigate adverse rate impacts
 23 associated with an expanded and sustained utility commitment
 to DSM.

24 Under the LAW Fund's proposal, the resulting Plans would be presented
 25 to the Commission for review and approval.

27 ⁵ Interested parties shall include RUCO, all parties to the
 28 utility's last rate case, all parties to the last IRP proceeding,
 and any other interested party that makes itself known to the
 utility such as through workshops.

1 The Companies expressed concerns regarding the collaborative
2 process as proposed by the LAW Fund and supported by ACAA. APS (for
3 example) was concerned that the collaborative process would seek to
4 replace the utility's management with an ad hoc committee of parties
5 ~~having~~ neither final responsibility for the success or failure of its
6 DSM programs nor the intimate knowledge of the APS system of
7 management. Further, APS was concerned that the process would
8 diminish the role of the Commission and Staff by limiting the
9 involvement of the Commission to that of a mere dispute arbitrator and
10 of Staff, to just one of many co-equal participants in the
11 collaborative process.

12 Staff recommended that within twelve months from the Commission's
13 Decision in each IRP proceeding, each utility solicit from parties to
14 this Docket (and other interested parties who make themselves known to
15 the utility and to Staff) specific proposals for DSM measures,
16 programs, and screening prior to preparing its Plan for the next
17 required filing, and that workshops on DSM proposals should be held.
18 Staff has indicated its willingness to help coordinate these workshops
19 as necessary.

20 We find that the proposed workshops on DSM activities would
21 promote greater public participation in the DSM planning process
22 without removing from the Companies their responsibilities to develop
23 and implement DSM programs and without removing from Staff its
24 responsibilities to review those programs. We believe this to be a
25 more reasonable approach than the proposed collaborative process since
26 the workshops provide all interested parties the opportunity for
27 input, while keeping ultimate planning and decision making authority
28 with the Companies and the Commission. Staff shall, therefore,

1 coordinate one set of workshops between IRP filings for the purpose of
2 obtaining input from the public on DSM plans. The Companies should
3 provide all parties with written material prior to the workshops
4 describing DSM screening criteria and DSM plans. Likewise, to make
5 the workshops more productive, all parties should provide the
6 Companies and each other with written proposals or comments prior to
7 the workshops. The workshops should be used to explore the
8 possibility of an agreement between the Companies and other parties on
9 DSM plans and screening criteria. If agreements are reached, they can
10 be noted in subsequent Plans.

11 Monitoring and Evaluation ("M&E") of DSM

12 The Companies have not completed the monitoring of savings from
13 their pre-approved DSM programs. Savings based on engineering
14 estimates for the largest programs in 1992 were presented by Staff in
15 its Staff Report. Engineering estimates may be in error because
16 customer behavior may alter the expected performance of the measure
17 and because on-site conditions may vary from those assumed in making
18 the engineering estimate. Thus, the savings estimates are to be
19 considered as preliminary and monitoring results may be different.

20 Utility progress on program M&E is hard to judge since monitoring
21 efforts are still underway. However, there seems to be varied
22 attention paid to the importance of assessing how well a program is
23 working in the field. Staff has recommended that the Companies give
24 the highest priority to M&E, including evaluation of kw and kwh
25 savings and process evaluation in their DSM efforts. We concur with
26 this as a general policy and will outline specific requirements
27 hereinbelow.

1 RUCO agreed with Staff that the Commission should require greater
2 efforts in improving M&E capabilities. RUCO, however, was concerned
3 that there is a danger that M&E could overshadow and distort the very
4 purpose of DSM. RUCO presented testimony that:

5 — M&E should be seen as a useful tool to inform decision
6 makers, not an end unto itself. While M&E is crucial, it
7 should not dictate the types of programs or technologies
8 offered by the utilities. A strong focus on evaluation
9 should not result in utilities only offering programs that
are easy to measure. M&E should be used to provide
information about DSM programs and resources, not as a
barrier to the development of effective programs.

10 RUCO has recommended that the Commission direct the Companies to focus
11 their M&E efforts on:

- 12 ♦ assessing net program effects (net savings);
- 13 ♦ assessing and reducing ratepayer risks (determining the
14 persistence and reliability of DSM resources); and
- ♦ improving their DSM program and delivery.

15 RUCO believes that generating public confidence in M&E capabilities is
16 a goal that the Companies and the Commission should strive to achieve.

17 Staff concluded that evaluation of kw and kwh savings should be
18 conducted using state-of-the-art methods in a competent, scientific
19 manner. The data and results should provide a comprehensive,
20 internally consistent account of the savings from DSM. Often, the
21 question of savings must be examined using two or three different
22 methods or databases because of uncertainty about baseline conditions
23 and wide confidence intervals around statistical results. There are
24 numerous techniques which can be used depending on the data, the type
25 of participants, and other factors. Staff's review of utility
26 evaluations of DSM savings is expected to be a scientific review
27 process in which Staff conducts its own analyses to test the validity
28 of the Companies' findings and in which Staff compares utility results

1 with results from other studies. Staff does not wish to develop rigid
2 guidelines that unduly constrain research in a rapidly developing
3 field. We concur with this approach, and encourage the parties to
4 coordinate M&E guidelines in the cooperative efforts described below.

5 — Advertising appears to be growing in importance as a cost element
6 of DSM programs. Staff concluded that advertising should be carefully
7 monitored by the utility to determine, at a minimum:

- 8 ♦ whether the mix of advertising and other program elements
9 (such as rebates or personal sales calls) is optimal;
- 10 ♦ how much advertising has changed consumer behavior;
- 11 ♦ whether advertising is well targeted;
- 12 ♦ whether the information content is appropriate;
- 13 ♦ how advertising supports other elements of the marketing
14 plan such as personal calls to building energy managers; and
- 15 ♦ how the advertising effort should change as the program
16 matures.

17 Staff recommended that the Companies include in the pre-approval
18 packet a monitoring plan for advertising for each DSM program whose
19 advertising costs are budgeted to exceed \$100,000 per year.

20 Staff also recommended that the Companies give greater emphasis
21 to measuring the impact of free ridership and free drivers on the
22 level of savings associated with their DSM programs.⁶ We recognize
23 the difficulties of analyzing free ridership and free drivers.
24 Nonetheless, this is an important issue in M&E and must be confronted.
25 We shall, therefore, require that the Companies measure the impact of
26 free ridership and free drivers on the level of savings associated
27 with their DSM programs in cases where such effects are likely to be

28 ⁶ "Free riders" are program participants who would have
undertaken the DSM measures without the DSM program and "free
drivers" are nonparticipants in the DSM program who undertook DSM
because of the existence of the program.

1 important and significantly influence the cost-effectiveness of a DSM
2 program.

3 Southwest Gas, ACAA, RUCO, and the LAW Fund indicated that they
4 would like to see a public or collaborative process for reviewing,
5 among other things, the M&E of the Companies' DSM programs. We agree
6 that the review of M&E of DSM should be a public process. However,
7 pre-approval of DSM projects should remain a Staff responsibility. A
8 public process will ensure that study designs take into account
9 relevant factors and that inferences from the analysis are reasonable.
10 Staff proposes that APS, TEP, AEPCO, and Citizens each make an annual
11 presentation at workshops covering the following topics:

- 12 ♦ study designs for DSM programs for which monitoring is
13 required (as indicated in Staff's pre-approval letter) and
14 for which monitoring has not yet begun or is about to begin
(including process evaluations);
- 15 ♦ progress reports on M&E projects underway (including process
evaluations); and
- 16 ♦ results from M&E projects that have been completed during
17 the previous year or are near completion (including process
evaluations).

18 We find that the proposed workshops, as well as the above
19 requirement of notification of pre-approval filings, will improve
20 public participation and enhance the Companies' M&E efforts. We
21 shall, therefore, require Staff to set up appropriate workshops once
22 a year to address M&E. The Companies should present estimates of kw
23 and kwh savings and describe process evaluations, as well as provide
24 copies of study plans, reports, and handouts in advance of the
25 workshops. We expect other parties to actively participate in the
26 workshops and provide constructive suggestions.

27 . . .

28 . . .

Financial Disincentives to DSM

Financial barriers to DSM have led the Commission to develop mechanisms for program cost-recovery, recovery of lost net revenues, and recovery of a profit or reward to make the utility indifferent between traditional supply side resources and DSM. According to Staff, relative to traditional regulation, a DSM program should ensure timely recovery of program costs, and a return equivalent to what the utility would have received from regulatory lag (increased sales between rate cases minus variable costs, i.e. net revenues) and from ratebasing future generating, transmission, and distribution capacity that will be deferred or avoided as a result of DSM.

Staff concluded that the Companies will need incentives to engage in DSM (beyond early pilot efforts) such as recovery of program costs, lost net revenues, and perhaps a profit or reward. Staff concluded that the Commission should continue on a case-by-case basis, in the context of a rate case, to design appropriate incentives. RUCO recommended that the Commission convene a working group of the Companies, Commission Staff and other interested parties to perform a thorough review of the potential regulatory disincentives (or need for positive incentives) for increased DSM resource acquisition. In particular, RUCO recommended that the issues of program cost recovery, lost net revenues, and financial incentives should be addressed. The LAW Fund indicated that current utility regulation:

- ♦ rewards shareholders for higher load growth regardless of the benefits that customers enjoy from this greater electricity use;
- ♦ penalizes shareholders for DSM programs that promote customer energy-efficiency regardless of the economic and environmental benefits such programs provide; and
- ♦ penalizes shareholders for energy-efficiency programs.

1 Several intervenors focused on mechanisms to remove financial
2 barriers to additional DSM activity. ACAA stated that if there is a
3 significant time lag between the implementation of a DSM program and
4 the next rate case, then the Companies should be granted deferral
5 ~~accounting~~ authority or be allowed to establish a balancing account
6 for recovery of costs at the time of the next rate case. The LAW Fund
7 proposed a collaborative process for at least APS to develop a package
8 of reforms that makes it financially possible for the Companies to
9 engage in large scale DSM.⁷ The LAW Fund proposed that the Commission
10 set up this collaborative process (primarily for just APS) over the
11 next 3 to 6 months to examine how to remove financial disincentives to
12 the Companies from engaging in DSM and to address short-term concerns
13 about the effects of DSM on electricity rates. A similar proposal for
14 a collaborative approach to compensating the utility for DSM was
15 raised by RUCO. Finally, the LAW Fund expressed concern about the
16 effects of the existing cap on APS' DSM cost recovery.

17 We believe that it is important for the Companies to be fairly
18 confident of recovering their prudent costs of DSM in order to
19 encourage them to engage in large scale DSM programs. Based upon the
20 evidence presented in this proceeding, recovery of program costs and
21 lost net revenues and possibly a reward or profit for DSM, should be
22 considered, recognizing that preferences for a particular recovery
23 mechanism vary among the parties.

24 As of the commencement of the hearing, APS has a \$4 million
25 annual cap in place on recovery of DSM costs. The cap was created
26 because of the uncertainty about APS' ability to implement DSM

27
28 ⁷ It is also intended to limit the impact of this on
nonparticipants, an issue that motivates the Law Fund's proposed
bonus program.

1 programs and because it was expected that APS would file a rate case
2 in which the cap could be modified or eliminated more quickly than is
3 turning out to be the case. APS testified that all costs of approved
4 DSM programs, including net lost revenues, should be recovered through
5 the APS Energy Efficiency and Solar Energy Fund ("EEASE Fund")
6 approved by the Commission in Decision No. 57649 (December 6, 1991).
7 Although a cost deferral mechanism recognizes the DSM expenditures for
8 future recovery, the timely recovery of program costs, lost net
9 revenues and incentives, provides a more appropriate form of
10 regulatory treatment for DSM. Finally, in TEP's recent rate case,
11 cost recovery was limited in magnitude by TEP's plans as of the time
12 of the rate case hearing.

13 Although RUCO and the LAW Fund propose a collaborative approach
14 to removing disincentives to DSM, it is not clear that TEP and APS are
15 holding back on DSM because they need additional incentives. Rather,
16 any financial disincentives are more likely attributable to the
17 limitations on cost recovery imposed during rate cases and potential
18 impacts of DSM on rates. Staff has recommended a deferral account
19 approach for APS and TEP to accommodate much larger DSM efforts by
20 these companies.

21 To encourage APS and TEP to significantly enlarge their
22 respective DSM programs, we shall adopt a deferred accounting approach
23 as described below. The Companies desiring deferred accounting must
24 file for Commission approval.⁸ We direct the Companies to include the
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26
27 ⁸ Any utility may make an application for a deferred
28 accounting order. At this time, AEPCO has no cap on DSM programs
and Citizens already has a deferral account. However, Citizens may
wish to propose modifying its account to include lost net revenues.

1 following essential elements in their applications for a deferred
2 accounting order:

- 3 ♦ A DSM savings target;
- 4 ♦ A specific DSM program consisting of cost-effective DSM
5 measures;
- 6 ♦ An effective M&E plan; and
- 7 ♦ A program designed to manage revenue impacts to the utility
8 and hence ratepayers.

9 If any of these essential elements is deficient in the Companies'
10 filing, no deferred accounting order will be granted.

11 It would be useful for parties to this proceeding to meet
12 publicly in workshops with APS and TEP (prior to the utility filing
13 for Commission approval of specific accounting authority) to discuss
14 how the deferral account would work and to consider the rate impacts
15 of the proposed level of deferrals. We direct Staff to set up such
16 workshops and coordinate participation by the Companies. For costs in
17 excess of those included in base rates or existing capped surcharges,
18 deferred accounting is appropriate if ratepayers have a reasonable
19 probability of getting the savings DSM programs can provide. The
20 public review of DSM M&E described above will provide a procedure to
21 establish that assurance.

22 Costs to be included in the deferral account are program costs
23 (e.g., administrative costs, rebates, M&E costs, and the like) and
24 lost net revenues (if authorized)⁹ and, if already authorized, a
25 reward for deferring the return on capacity additions deferred by DSM.
26 Costs may only be entered into the deferral account if they are
27 associated with programs pre-approved by Staff and when kw and kwh

28 ⁹ APS already has authority to recover lost net revenues and
the Commission authorized recovery of lost net revenues in TEP's
recent rate case.

1 savings are reasonably probable and can be analyzed and measured using
2 monitored data¹⁰ (following a public review of the analysis in the
3 annual workshops on M&E described above.)

4 Additionally, program costs may be entered in the deferral
5 account if they are associated with monitored pre-approved educational
6 or research programs from which no kw or kwh savings can be
7 practically derived. The term "monitored" refers to both analysis of
8 kw and kwh savings and process evaluations. Finally, costs included
9 in the deferral account may be recovered at the next rate case,
10 possibly amortized over several years because of their potentially
11 large magnitude. Consistent with Decision No. 57589, deferred amounts
12 may accrue interest at the approved cost of capital of the utility.

13 As an alternative to the recovery of lost net revenues, the LAW
14 Fund proposed a form of decoupling, called statistical recoupling. In
15 particular, decoupling was proposed by the LAW Fund and is discussed
16 in the Staff Report as a means to unlink utility revenues and sales,
17 thereby removing incentives for utilities to sell more electricity and
18 remove disincentives to engage in DSM. Decoupling can, if properly
19 done, remove the incentive to sell more electricity between rate
20 cases. We leave the door open to all innovative ideas on how to
21 unlink revenues and sales and expect the parties to offer suggestions
22 on this topic in future IRP proceedings.

23 In light of the above, the Commission shall consider incentives
24 for DSM that focus on recovery of program costs, recovery of lost net

25 ¹⁰ If the M&E indicates that a pre-approved program is not
26 turning out to be cost-effective or that a pre-approved program
27 should be significantly modified, costs up to the time that the M&E
28 was completed should be included in the deferral account. For
deferral of costs incurred after that time, the utility should make
appropriate modifications in the program (assuming the program is
not terminated.)

1 revenues, and, if appropriate, recovery of a reward for deferring
 2 returns on future capacity. As appropriate, the Commission will also
 3 consider other means of addressing the incentives to sell more energy
 4 and the disincentives to DSM.

5 DSM and The Energy Policy Act of 1992

6 Section 111 of the Energy Policy Act of 1992 pertains to IRP and
 7 DSM. In particular, several standards are added to the Public Utility
 8 Regulatory Policies Act of 1978 ("PURPA"), 16 U.S.C. §2621(d):

9 (7) Each electric utility shall employ integrated resource
 10 planning.¹¹ All plans or filings [before the Commission]
 11 ... must be updated on a regular basis, must provide the
 opportunity for public participation and comment, and
 contain a requirement that the plan be implemented; and

12 (8) The rates allowed to be charged by a State regulated
 13 electric utility shall be such that the utility's investment
 14 in and expenditures for energy conservation, energy
 15 efficiency resources, and other demand side management
 16 measures are at least as profitable, giving appropriate
 17 consideration to income lost from reduced sales due to
 investments in and expenditures for conservation and
 efficiency, as its investments in and expenditures for the
 construction of new generation, transmission, and
 distribution equipment;¹² ... energy conservation, energy

18 ¹¹ PURPA defines IRP as "... a planning and selection process
 19 for new energy resources that evaluates the full range of
 20 alternatives, including new generating capacity, power purchases,
 21 energy conservation and efficiency, cogeneration and district
 22 heating and cooling applications, and renewable energy resources, in
 23 order to provide adequate and reliable service to its electric
 24 customers at the lowest system cost. The process shall take into
 25 account necessary features for system operation, such as diversity,
 26 reliability, dispatchability, and other factors of risk; shall take
 27 into account the ability to verify energy savings achieved through
 energy conservation and efficiency and the projected durability of
 such savings measures over time; and shall treat demand and supply
 resources on a consistent and integrated basis." 16 U.S.C. §2602
 (19). The term system cost "... means all direct and quantifiable
 net costs for an energy resource over its available life, including
 the cost of production, distribution, transportation, utilization,
 waste management, and environmental compliance." 16 U.S.C.
 §2602(20).

28 ¹² PURPA also states that "[t]he rates charged by any
 electric utility shall be such that the utility is encouraged to
 make investments in, and expenditures for, all cost-effective

1 efficiency resources and other demand side management
2 measures shall be appropriately monitored and evaluated.

3 PURPA requires state utility regulators to consider the standards
4 indicated in 16 U.S.C. 2621(d) and determine whether each is
5 appropriate to implement. PURPA also requires state utility
6 regulators to commence consideration of the standards within two years
7 of October 23, 1992 and to complete the consideration within three
8 years (16 U.S.C. §2622 (b)).

9 We have considered the standards listed above through the
10 Commission's IRP rules (A.A.C. R14-2-701 et seq.) which have been in
11 effect since 1989 and through rate case decisions cited in Section D,
12 Table 10 of the Staff Report. With respect to making DSM as
13 profitable as investments in capacity, we find that the Commission has
14 initiated efforts in this direction as discussed above.

15 ACAA proposes that the Commission modify its IRP rules to direct
16 the implementation of Plans as approved, modified or rejected, because
17 it believes that without such action, there is a danger of the IRP
18 process becoming simply informational. We agree that we do not want
19 just an informational process. We are, however, reluctant at this
20 time to institute an approval process for Plans because doing so may
21 limit future Commission review of utility actions in rate cases and
22 other forums. We find that formal Commission approval of a Plan is
23 not necessary for its implementation. IRP is a dynamic process and,
24 as a result of the hearings in this Docket, the Commission has the
25 opportunity to shift the direction of Plans. Second, even without a

26 improvements in the energy efficiency of power generation,
27 transmission, and distribution.... State regulatory authorities ...
28 shall consider the disincentives caused by existing ratemaking
policies and practices, and consider incentives that would encourage
better maintenance, and investment in more efficient power
generation, transmission and distribution equipment."

1 formal approval process, we have seen progress on DSM as a result of
2 the previous Commission decision on IRP (Decision No. 57589). As
3 filed, the Companies' Plans may not fully and properly evaluate either
4 DSM or renewables. However, the Commission can and does rectify any
5 deficiency by ordering the Companies to implement those intervenor and
6 Staff recommendations it finds appropriate. We find that
7 implementation of the Plans is an inherent requirement of the filing
8 under the rules, as well as under the decisions that arise thereunder.
9 DSM and Clean Air Act Amendments of 1990

10 Under the Clean Air Act Amendments of 1990, Section 404(f), the
11 Environmental Protection Agency ("EPA") allocates allowances for
12 sulfur dioxide emissions on a first-come, first-served basis to
13 electric utilities who avoid emissions of sulfur dioxide via cost-
14 effective conservation measures or renewable energy sources. 42
15 U.S.C. §7651c(f). There is to be a Conservation and Renewable Energy
16 Reserve consisting of 300,000 such allowances, each allowing the
17 utility to emit one ton of sulfur dioxide. A utility may use the
18 allowance itself or sell it to another utility. Allowances for
19 conservation and renewable energy are to be allocated on the basis of
20 kwh saved by conservation or generated by renewable energy after
21 January 1, 1992 and before December 31, 2000.¹³

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23
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26 ¹³ The value of allowances is still unclear because sales of
27 allowances have been limited to date. In early 1993, the EPA
28 auctioned 150,000 allowances (as authorized in 40 CFR 73.70.)
Prices paid for allowances usable in 1995 averaged about \$157 and
ranged from \$131 to \$450, and prices paid for allowances usable in
2000 average about \$136 and ranged from \$122 to \$310. Data from
"The Energy Report", April 5, 1993, pp. 203 - 205.

To be eligible for these allowances, the electric utility must own or operate at least one affected unit,¹⁴ and must adopt and implement a least cost energy conservation and electric power plan which evaluates supply and demand side resources, including renewable resources. The plan must be approved or accepted by appropriate state utility regulators. For DSM measures, the Secretary of Energy must certify that the state regulator has established rates and charges which ensure that the net income of the utility after implementation of DSM is at least as high as the net income would have been if the energy conservation measures had not been implemented. The Clean Air Act Amendments also require that the Commission approve utility applications for these allowances.

According to 40 CFR 73.82 (58 Federal Register 3696, January 11, 1993), the Commission must approve or accept¹⁵ the utility's least cost plan or least cost planning process and certify that the least cost plan or planning process meets the following requirements:

- ♦ provides an opportunity for public participation;
- ♦ evaluates a full range of existing and incremental resources to meet demand at lowest cost;
- ♦ treats DSM and supply resources on a consistent and integrated basis;
- ♦ considers system diversity, reliability and other risk factors; and

¹⁴ An "affected unit" is a generating unit subject to emission reduction requirements or limitations of the Clean Air Act Amendments. 42 U.S.C. §7651a(2). A list of affected units may be found in 56 Federal Register 63153 et seq., December 3, 1991.

¹⁵ The term "accept" follows from EPA's recognition that "... some State regulatory authorities are unwilling to approve a utility's least cost plan out of concern that such approval will tie the hands of future State regulatory bodies. However, these State authorities will 'accept' a least cost plan if it complies with the State regulatory authority's requirements" (58 Federal Register 3621, January 11, 1993).

♦ is being implemented to the maximum extent practicable.¹⁶

We find that the Commission's IRP process incorporates these features and meets the criteria for obtaining allowances. We find, therefore that our IRP process meets the requirements of 40 CFR 73.82 (a)(4) and ~~(a)(6)~~ regarding allowances from the Conservation and Renewable Energy Reserve.¹⁷ Additionally, we shall consider the benefits to Arizona utilities with regard to gaining additional sulfur dioxide allowances when determining, in rate cases, whether to allow the utility to recover lost net revenues or rewards for DSM savings.

Miscellaneous

SRP raised a concern regarding Staff's conclusion in its Staff Report regarding high efficiency HVAC programs. Staff concluded that "given current costs, increasing the SEER of air conditioners or heat pumps by itself is likely to be only marginally cost-effective, at best." SRP disputes this conclusion. SRP has a high efficiency HVAC program among its DSM options and is concerned with the implication that the Commission would not allow the Companies to recover such program costs. There is nothing that precludes a utility for filing for approval for recovery of a high efficiency HVAC program. We are making no determination herein with respect to whether such approval should be given. Each program will still be considered on a case-by-case basis.

¹⁶ The plan or planning process may take into account other factors such as environmental costs and benefits or social factors.

¹⁷ The Commission must also certify that the DSM measures for which allowances are sought are consistent with the least cost plan or planning process (40 CFR 73.82 (a)(5)). This would be done on a case-by-case basis for each application.

III. Supply Side Issues

Introduction

Supply side issues generally relate to an electric utility's ability to supply electricity to its customers (from conventional and unconventional sources and from purchases), and the transmission and distribution of electricity to end-users. Between 1993 and 2010, the Companies plan to add about 2285 MW of new generating capacity at a cost (present value) of \$812 million. The first unit to be added is a 75 MW gas-fired combustion turbine to serve Citizens, starting in 1996. Most of the planned capacity to be added between 1993 and 2010 is gas-fired. Combined cycle units comprise nearly half of the planned additions, combustion turbines account for about 25 percent of the new capacity, baseload units comprise 15 percent of the new capacity, and the remainder consists of increasing the capacity of existing plants (uprating) and the use of other technologies, including 10 MW of photovoltaics and 2 MW of fuel cell production.

Staff and the Law Fund believe that it is necessary for the Companies to increase their level of commitment to renewable resources. Staff and the LAW Fund raised concerns that the Companies have not given due consideration to the possibility of significantly higher natural gas prices over the lifetimes of the proposed new generating plants and that the Companies have not planned to hedge their bets on future power plant technologies by diversifying their resource choices. Staff concluded that the potential for large real (inflation adjusted) price increases for natural gas is sufficient to warrant serious consideration of renewable resources; especially solar thermal resources.

1 The LAW Fund presented evidence that integration of cost-
2 effective DSM and renewable resources into the Companies' IRPs on a
3 sustainable basis will lower utility costs of service, thereby freeing
4 dollars that would otherwise be invested in meeting the demand for
5 utility energy services for investment elsewhere in the economy. The
6 LAW Fund believes that integration of DSM and renewables in IRPs also
7 introduces greater resource diversity into Arizona utility resources,
8 thereby buffering ratepayers against the volatility of fossil fuel
9 prices. Additionally, the LAW Fund testified that DSM and renewables
10 emit no or little oxides of carbon, sulfur, nitrogen, and little or no
11 particulate matter or air toxins, all of which are implicated in such
12 problems as regional visibility degradation, acid rain, global climate
13 change and impacts on human health and terrestrial ecosystems. The
14 LAW Fund has also taken the position that increasing the reliance of
15 the Companies on DSM and renewables will place Arizona on the road
16 toward sustainability in its use of resources to meet the demand for
17 utility energy services.

18 Although gas-fired resources may be economical under the
19 Companies' base case economic assumptions, the evidence in this
20 proceeding demonstrates that gas prices can vary significantly.
21 Natural gas prices, now at extremely low levels by recent historical
22 standards, could be affected by a number of factors thereby raising
23 utility costs and rates.

24 In contrast to the price risks associated with natural gas
25 plants, once established, renewable resources¹⁸ are not subject to
26

27 ¹⁸ Common forms of renewable energy resources include:
28 photovoltaics; solar thermal resources such as parabolic troughs,
parabolic dishes, and central receivers; windpower; biomass
consisting of wood, wood waste, agricultural waste, municipal solid
waste, and landfill and digester gas; geothermal resources,

1 these uncertainties. These renewable resource technologies are
2 powered by energy sources which are not affected by market pressures.
3 While such renewable resource technologies do have some operating and
4 maintenance costs, these costs tend to remain stable or increase only
5 gradually over time. In contrast, fuel prices can change dramatically
6 and unpredictably in a short time. Increasing the share of solar and
7 other renewable resource technologies in a utility's portfolio of
8 resources provides a hedge against the risk that the costs of fossil
9 fueled power plants will be increased substantially by forces outside
10 the control of the utility. A diversified resource portfolio
11 containing increasing amounts of solar and other renewable resources
12 will thus protect consumers from facing electricity production costs
13 which are significantly higher than expected. At the same time, it
14 should be acknowledged that the reduction in risk could result in
15 overall higher costs.

16 Renewables can also have benefits as a hedge against the
17 environmental risks associated with running existing units. The
18 Companies currently rely on coal and nuclear plants to meet the
19 overwhelming majority of Arizona's energy needs. Although these
20 plants are currently relatively inexpensive to operate, future
21 regulatory changes could significantly alter this situation. For
22 example, efforts to deal with global climate change or other
23 unresolved environmental problems associated with coal could
24 significantly increase the costs of operating coal plants. Similarly,
25 the changes in the regulatory environment dealing with the disposal of
26 nuclear waste could also raise the cost of running the Arizona nuclear
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including hydrothermal resources and hot dry rock; and hydropower.

1 units. Again, renewable resources could provide a partial hedge
2 against these environmental risks.

3 Based upon the Plans that were filed, it is necessary for the
4 Companies to increase their level of commitment to renewable resources
5 in the manner set forth hereinbelow. There is, however, disagreement
6 with respect to how this is to be achieved. The following analysis
7 deals with the major issues discussed at the hearing.

8 Renewables Working Group

9 Staff proposed a joint evaluation of renewable technologies using
10 decision analysis in which a working group of Staff and other parties
11 to the IRP docket would pursue several objectives:

- 12 ♦ to develop a better understanding of how to evaluate the
13 risks and benefits of gas-fired plants and renewable
14 resources (with emphasis on solar thermal plants and
15 possibly windpower), by inviting experts on decision
16 analysis, solar and wind technology, and conventional
17 technology to make presentations;
- 18 ♦ to collaboratively develop a decision analysis of a generic
19 combined cycle unit, a generic solar plant, and possibly a
20 generic wind plant for the purpose of improving the parties'
21 understanding of how to do such an analysis; and
- 22 ♦ to collaboratively develop suggestions on how utilities
23 should analyze the risks and benefits of renewables and
24 conventional technology in their next Plans.

25 Staff proposed that it chair the working group and that the working
26 group should plan to complete its work within one year from the
27 effective date of this Decision. The product would be a discussion
28 paper on the application of decision analysis to renewable and
conventional resource options.

Because of the important technical issues involved, we believe
that a working group consisting of Staff and utility planners (as well
as any other parties to this Docket who wish to participate) should be
created to develop a framework (or frameworks) to thoughtfully handle

1 uncertainty in supply side IRP decisions, to accomplish the three
2 goals listed by Staff, and to complete a discussion paper within one
3 year. Staff should coordinate the working group's activities.
4 Details of the procedures used by the working group should be
5 determined by the participants at the beginning of the process and the
6 working group should determine the range of analytical methods to be
7 explored.¹⁹ We envision that the working group's effort will be
8 primarily educational.

9 Long-Term Set Asides

10 Staff recommended "flexible", long-term, set asides²⁰ for
11 renewable resources of 40 MW each for AEPCO and Citizens, and set
12 asides of 160 MW each for TEP and APS, all to be added by 2009. A set
13 aside is an amount of capacity using renewable resources which must be
14 added by the utility by a given date, subject to the flexibility
15 condition noted below. Staff argued that the set asides provide a
16 signal to the Companies that renewables are important and that

17
18 ¹⁹ The working group should strive to focus its activities on
19 productive methods of decision analysis such as by isolating key
20 variables, quantifying those variables using expert opinion and the
21 literature, estimating cumulative probability distributions from
22 expert opinion and the literature on the chances that the variables
will exhibit various values, and identifying the strategies which
will produce the lowest expected costs. The applicability of
sensitivity and scenario analyses can be determined by the working
group.

23 ²⁰ Staff recommends that nameplate capacity be used to
24 determine the quantity of renewables in place. In footnote 24 (page
25 E-26) of the Staff Report, Staff indicated that the capacity of
26 renewables should be determined in terms of the equivalent amount of
27 combustion turbine or combined cycle capacity. This recommendation
28 inappropriately focused on replacing intermediate and combined cycle
capacity with renewables capacity. During the course of the
hearing, two problems with this approach surfaced: a) renewables
may be used for purposes other than supplanting central station
generation, as stated by Staff witnesses; and b) it may be
administratively complex to determine equivalent capacities for a
variety of technologies, since a different analysis would have to be
conducted for each technology in each of its potential applications.

1 research, development, commercialization, and implementation of
2 renewables are not expendable at the first sign of short-term company
3 financial problems.

4 The LAW Fund also supported the use of set asides coupled with
5 a request for proposals for suppliers of renewable resources to
6 install and possibly operate those resources for the Companies as a
7 mechanism to achieve the set asides. In particular, the LAW Fund
8 proposed that the Companies issue RFPs to obtain 250 GWH per year of
9 renewable energy to be in service between 1998 and 2001. According to
10 Staff, this proposal would mean about 80 MW of renewable capacity in
11 the short-term.²¹

12 Staff's argument supporting the need for flexible set asides
13 included the following factors:

- 14 ♦ in the face of the potentially large increases in the price
15 of natural gas, a portfolio of new peaking and intermediate
16 resources consisting only of natural gas-fired resources is
a poor bet;
- 17 ♦ a utility commitment to a gas-fired resource coming on line
18 around 2010 will require gas purchases well into the mid-
21st century when gas prices and availability are unknown;
- 19 ♦ the contribution of renewables should be large enough to
20 significantly hedge the utility's bet that gas will be the
cheapest generation source;
- 21 ♦ the amount of renewables capacity should not exceed the
22 amount of intermediate and peaking capacity additions
planned by the utility; renewables may be best suited as
23 peaking and intermediate resources. The set aside is about
one fourth of planned intermediate and peaking additions
over the period 1993 to 2009;
- 24 ♦ the contribution to a single utility by renewables can be
25 met through a variety of technologies and requires only a
26 modest number of projects of moderate size, such as
photovoltaics in a few distribution system sites, one solar
thermal central receiver plant, one or more wind project

27 ²¹ We view the LAW Fund's proposal as a stepping stone or
28 intermediate goal between Staff's long-term and short-term set aside
recommendations.

1 sites, and several distributed or central dish/Stirling
2 projects;

- 3 ♦ the Companies should undertake extensive research and
4 development activities with regard to renewables to better
5 define costs and performance characteristics and to
6 encourage the commercialization of renewables at costs lower
7 than today's costs;

- 8 ♦ the contribution of renewables should be large enough to
9 cause the Companies to order enough renewable technology so
10 that manufacturers of renewables can gain economies of scale
11 in production and attract investors, thereby causing the
12 price to come down for future buyers. The Companies will be
13 doing this at the same time that utilities in other states
14 are doing the same thing. Therefore, many utilities will be
15 contributing to the process of reducing costs and promoting
16 commercialization of renewable technology;

- 17 ♦ the contribution of renewables should be large enough to
18 enable the utility to gain useful experience in commercial
19 scale applications of renewables;

- 20 ♦ the timing of the set aside is such that, with active
21 research and development activities by the Companies and
22 others, commercial scale applications of solar thermal
23 technologies are expected to be available at costs lower
24 than today's costs; and

- 25 ♦ weak participation by the Companies in research,
26 development, and commercialization of renewables will only
27 delay the commercial availability of economic renewable
28 technologies, thereby costing consumers more than necessary
in high fuel prices.

Staff proposes that the Companies could obtain the proposed renewable capacity by constructing and owning their own renewable resource facilities, sharing facilities among several utilities, requesting bids from others to construct and operate renewable resource plants, and assisting customers to install and operate renewable energy technologies at the customers' sites to generate electricity directly for customer use. Short-term set asides (described hereinbelow) may be used by the Companies to count toward the long-term targets described above. Also, because IRP is a dynamic activity, Staff argued that the set asides may have to be revised on a regular basis to reflect fuel cost changes, changes in the costs of

1 renewables, changes in load forecasts, changes in the need for
2 additional capacity, and other factors.

3 The proposed long-term set asides generated much controversy and
4 testimony. Citizens, APS, TEP, and SRP believe that the Staff
5 ~~proposal~~ for set asides is premature and that additional study is
6 needed before committing to renewables. APS stated that "any
7 commitment to a large 'set aside' for renewables is at best premature
8 and would be ... analogous to the Commission agreeing to buy something
9 without knowing the price, either for what is being bought or for
10 alternatives." Citizens stated that, "given the acknowledged need for
11 additional discussion, a proposal to obligate millions of dollars of
12 incremental capital costs (to renewables) is a premature leap-of-
13 faith."

14 The Companies also expressed concern that committing to rigid set
15 asides may ultimately turn out to be needlessly costly because the set
16 aside capacities are too large (or too small) or because conditions
17 such as load forecasts or generation costs may be far different than
18 what was planned 15 years earlier, and that blindly adhering to a
19 rigid set aside long after it has become economically stale would
20 counter the aim of resource planning. AEPCO argued that mandatory
21 set asides of renewable resources violate principles of least-cost
22 planning, create a commitment to renewables that is premature, impair
23 the competitive position of AEPCO, undermine system reliability,²²
24

25
26
27 ²² AEPCO also indicated other concerns such as the seasonable
28 variation of power from wind turbines and photovoltaic resources
combined with their lack of dispatchability would strain the
operation of AEPCO's generation system.

1 make Rural Electrification Administration ("REA") financing
2 uncertain,²³ and are inequitably large.²⁴ Similar arguments were put
3 forth by the other Companies.

4 Further, the Companies argued that Staff's recommendation for
5 long-term set asides was analogous to its recommendation in the last
6 IRP proceeding wherein Staff recommended the adoption of a rebuttable
7 presumption that future construction of intermediate and peaking power
8 plants should be solar thermal power. The Commission rejected this
9 recommendation on the basis (in part) that there was not sufficient
10 evidence to support one industry (solar) enjoying the proposed
11 rebuttable presumption over all other industries. Although there are
12 similarities, we do not agree that the recommendation of long-term set
13 asides is totally analogous to the solar power recommendation.

14 We find that the time is ripe for serious consideration of
15 renewables over the long run, well beyond the efforts described in the
16 Companies' Plans. Further, we find that it may be necessary to hedge
17 society's bets on future fuel costs by planning for an increased
18 amount of renewables in the utility's portfolios of resources. We
19 also find that it is necessary that when the time comes to commit to
20 new central station generation plants, the Companies will have the
21 knowledge to select, install, and operate renewables and will have
22 ordered enough renewables from suppliers so that the capital costs of
23 renewables decline from today's levels. We are cognizant of the

24
25 ²³ Financing for construction of new generating units is
26 currently obtained in conjunction with guarantees provided by the
27 REA. The REA requires the submission of a least-cost plan as part
of any application for funding.

28 ²⁴ While 40 MW may be 25 percent of the identified generation
additions in AEPCO's 1993 IRP, it is 40 MW more than AEPCO has
committed to acquiring as of December 1993.

1 Companies' responsibilities to develop and implement their own Plans
2 and desire to minimize inserting the Commission or other parties
3 unduly into those responsibilities. The IRP process is intended to
4 change the direction of Plans when those Plans do not fully take into
5 account significant relevant factors such as future natural gas prices
6 or the need for the Companies to actively participate in the
7 development of cost-effective renewables. Because IRP is a dynamic
8 activity, Staff has proposed that the set asides be "flexible" in
9 order for the Companies and the Commission to be able to take into
10 consideration changes in fuel costs, the costs of renewables, load
11 forecasts, the need for additional capacity, and technology in future
12 IRP proceedings.

13 Although we agree with the fundamental concept and recommendation
14 that Staff has posited, we are concerned, however, that before we
15 impose what will be in effect, mandatory long-term set asides
16 (regardless of the "flexibility"), there needs to be additional notice
17 and opportunity for the Companies and other interested parties to be
18 able to respond to, and conduct additional study and planning for,
19 such a requirement. We will, therefore, require that setting the
20 appropriate long-term goals for the year 2009 become a topic of the
21 working group (discussed hereinabove) and part of the discussion paper
22 that will be submitted to the Commission.

23 Further, the LAW Fund has recommended that the Commission direct
24 the Companies to develop comprehensive renewable resource plans as
25 part of their next IRP filing that aim at capturing the full potential
26 of renewable resources to serve electricity needs. Such comprehensive
27 plan should address the following key elements:

- 28 ♦ developing an information base on renewable resources on
which Arizona utilities may rely;

- ♦ providing for a sustained, focused research, development, and demonstration effort aimed at preparing the way for the utilization of viable renewable resource technologies;
- ♦ assuring that IRPs developed by utilities in Arizona take advantage of renewables;
- ♦ proposals for fine-tuning the Commission's regulatory policies so that they encourage utility renewable resource initiatives that are consistent with the first three elements; and
- ♦ evidence that the Companies are tapping the increasing federal funding support for renewable resources.

We concur with the LAW Fund that the Companies should include the above elements in their next IRP filings. Further, notwithstanding the opposition expressed in this proceeding by the Companies regarding long-term set asides, if by the next IRP filing the respective Companies do not propose in their Plans reasonable alternatives to Staff's recommendations regarding the set asides, the Commission will reconsider adopting Staff's recommendations regarding mandatory, albeit flexible, set asides to be implemented by the year 2009.

Short-Term Set Asides

Until recently, renewable energy efforts by the Companies have been primarily either research and development efforts or small-scale early applications installed by innovative field engineers. Staff argued that it is time to accelerate these efforts for several reasons, including the following:

- ♦ there may be significant production economies-of-scale as renewables move into mass production, driving down the cost of renewable-generated electricity;
- ♦ economies-of-scale in production can be achieved through coordinated, joint purchases to establish viable markets for the new technologies; and
- ♦ renewable technologies are significantly different from conventional, fossil fuel technologies, requiring new technology learning curves that should be started

immediately for renewables to be implemented within the planning horizon. In order for renewable energy to be effectively included in the generation mix in future years, utility personnel must start today to learn about the characteristics of renewables in utility systems. The best way for utilities to learn is to start, on a small scale, with the design, installation, and operation of renewable systems. Then, probably after the turn-of-the-century, the Companies will be prepared to install the multi-megawatt and hundreds of megawatt renewable plants that will be required.

The LAW Fund agreed with Staff that developing renewable resource programs to achieve short-term renewable resource acquisition goals will help ensure that the Companies make a significant contribution to the development of solar resource technologies without carrying a disproportionate share of the regional or nationwide financial burden. The LAW Fund noted that this commitment will serve several important purposes such as:

- ♦ a means to exert market pull to reduce the ultimate direct costs of renewable resource technologies;
- ♦ enabling the Companies to gain experience with these resources; and
- ♦ signaling the Companies' IRP commitment to develop these renewables as cost-effective electric system resources.

Staff has recommended that at a minimum, the Plans due to be filed by December 31, 1995 include the following mandatory short-term set asides for renewables to be implemented not later than December 31, 2000:

AEPCO	1,000 kw ²⁵
Citizens	1,000 kw
TEP	5,000 kw
APS	12,000 kw

Under Staff's proposal, the Companies should be allowed to credit renewable energy systems installed between January 1, 1993 to December

²⁵ In the case of AEPCO, projects undertaken by member cooperatives can be counted toward the goal.

1 31, 2000 toward their respective short-term set asides. The intent of
2 the short-term set asides is to enhance learning about renewables to
3 prepare for larger efforts that will probably be required after
4 2000.²⁶

5 — During the hearing, APS indicated that it is willing to strive
6 toward a "goal" of 12 MW for renewables by 2000 and TEP indicated that
7 it is willing to strive toward a goal of 5 MW for renewables by 2000.
8 We regard these statements as serious commitments and will accept them
9 as planning goals which are predicated upon articulated assumptions.
10 However, if APS and TEP appear to fall significantly short of meeting
11 these goals, we shall reconsider short-term set asides. If
12 assumptions in setting these goals do not materialize, the goals may
13 be revisited and modified in keeping with the facts known at such
14 time. As for Citizens and AEPCO, we find that the short-term set
15 asides of 1 MW each are reasonable and, to be consistent with our
16 treatment of APS and TEP hereinabove, will treat these set asides as
17 planning goals for the year 2000.

18 Finally, although we will not adopt the targets proposed by the
19 LAW Fund, we encourage the Companies to consider Green Requests for
20 Proposals (RFPs)²⁷ for renewables as a means of implementing the
21 short-term goals and, in all likelihood, future long-term set asides.

22 Other Issues Regarding Renewables

23 Staff also made the following recommendations on renewable energy
24 sources:

25
26 ²⁶ The short-term set asides can be counted toward the long-
27 term set aside requirements that may be required in the future.

28 ²⁷ Green Requests for Proposals (RFPs) is a competitive bid
solicitation process used as a means for a utility to acquire
renewable resources from third parties.

- 1 ♦ each utility must develop a database of existing renewable
2 energy resources within its system within six months from
3 the effective date of this Decision. These inventories
4 should be revised annually and submitted to the Commission
5 Staff each year as part of the historical data filings
6 required under the IRP rules;
- 7 ♦ each utility should prepare a three year renewable resource
8 action plan as part of its filing requirements for an action
9 plan under the Commission's IRP rules, starting with the
10 plans to be submitted by December 1995;²⁸
- 11 ♦ the Companies should include in their next Plans (to be
12 filed by December 31, 1995) explicit discussions of their
13 research and development plans and activities regarding
14 renewables, including descriptions of projects undertaken
15 and costs of those projects;
- 16 ♦ the Commission should consider (in rate cases) allowing cost
17 recovery for prudent investments in renewable generation
18 demonstration projects (such as Solar Two) to better
19 determine the costs and output potential of the technology;
- 20 ♦ the Companies should recover prudent costs of set aside
21 renewable resources (within limits on the cost per kw to be
22 determined in future resource planning hearings or rate
23 cases) after Commission consideration of utility cost
24 estimates and proposals for cost recovery. The criteria for
25 determining the limits on costs should include: estimates
26 of costs from engineering studies or field experience; the
27 costs of other (alternative) renewable technologies; the
28 degree to which commercialization of the technology has
 progressed; and the likelihood that the proposed technology
 can be cost-effective in the future (if not currently cost-
 effective)²⁹; and
- ♦ the Commission's policy stated in Decision No. 57589,
 concerning the provision of information on photovoltaics to
 potential line extension customers in remote areas, based on
 Staff guidelines, should be continued.

²⁸ The LAW Fund recommends that the Commission order Arizona
utilities to develop comprehensive renewable resource programs
within one year from the effective date of this Decision. We find
that Staff's proposal is similar and there is no need to adopt this
proposal as well.

²⁹ If the costs turn out to be greater than the limits, the
utility could request that the Commission raise the limit. If the
utility contemplates such a proposal, it should have well-
documented, logical support for the request indicating that new
information alters the situation.

1 TEP supports Staff's recommendation that TEP be allowed to
2 recover costs incurred for participation in such pre-approved
3 renewable projects. The Company indicated further that it should be
4 permitted to include in rate base and earn a return on investments in
5 renewables as such pre-approved renewable resources become a part of
6 the resource mix. TEP also noted that such renewable capacity should
7 be treated in a way that does not affect the determination of the
8 amount of Springerville Unit No. 2 to be included in rate base.

9 We find that each of the Staff recommendations generally supports
10 our commitment to renewables as expressed hereinabove, and we shall
11 adopt them herein as modified. We believe that renewables capacity
12 may be put into rate base (in rate cases) and earn a return, and we
13 shall consider such proposals in rate cases. We further take note of
14 TEP's concern about potential conflicts between the amount of
15 Springerville Unit No. 2 which is rate-based and our requirements on
16 renewables. Since we have not ordered any mandatory renewable
17 amounts, we do not find any conflicting policies.

18 The LAW Fund has also recommended that the Companies consider
19 Green Pricing Programs, which offer consumers the opportunity to
20 purchase greater amounts of renewable resource produced electricity
21 than a utility or regulatory commission believes all utility customers
22 should support. The Commission will not at this time require the
23 implementation of Green Pricing Programs.

24 Other Supply Issues

25 We conclude that competitive bidding may be used to obtain
26 utility resources, but also that such bidding processes must be
27 founded on a thorough understanding of transaction costs so that
28 contracts can be written which result in power and energy when needed

1 at reasonable cost without unduly transferring risks to the utility or
2 the ratepayer. Competitive bidding is useful but it is not a panacea.
3 At the same time, we also recognize that through its consideration of
4 transaction costs, a utility could use the bidding process to engage
5 in self-dealing or other practices that are not least cost. Staff
6 recommends that any Companies who wish to engage in supply or demand
7 side bidding inform Staff of all requests for bids at least 45 days
8 prior to issuing the request and submit to Staff a complete report on
9 the bids, the utility's evaluation of the bids, and the utility's
10 selection of the winner(s) no more than 30 days after selecting
11 winning bids. We find Staff's recommendation regarding competitive
12 bidding reasonable and shall adopt it herein³⁰.

13 With regard to state regulatory responsibilities and Regional
14 Transmission Groups, we shall require Staff to continue to participate
15 in Southwestern Regional Transmission Association ("SWRTA") meetings
16 on a regular basis to keep informed of transmission planning issues.

17 Staff argued that at present, there are no useful analyses of
18 savings in transmission and distribution costs resulting from DSM.
19 Consequently, it is not possible to adequately quantify the benefits
20 of avoiding or deferring transmission and distribution costs when we
21 evaluate demand side management measures. Staff recommended that the
22 Companies include in future Plans explicit analyses of the changes in
23 their transmission and distribution plans and associated savings
24 attributable to demand side management programs. We concur.
25 Estimates of transmission and distribution savings should be
26 determined from site-specific evaluations, considering deferrals of

27 ³⁰ This competitive bidding process does not apply to AEPCO's
28 competitive proposal solicitation process that is currently
underway.

1 transmission and distribution capacity resulting from planned DSM
2 programs.

3 With regard to Exempt Wholesale Generators (EWGs), in Decision
4 No. 58424 (October 14, 1993), we declined to adopt the Section 712
5 standards. We reaffirm our position in that discussion.

6 Under PURPA, utilities are obligated to purchase energy and power
7 from qualifying cogenerators and small power producers at rates up to
8 the utility's avoided costs. However, the Companies have not offered
9 capacity payments for purchases of power from qualifying facilities.
10 In our previous IRP Decision, the Commission ordered the Companies to
11 file proposed capacity and energy rates for purchases from qualifying
12 facilities ("QFs") in their 1992 resource planning filings. Only APS
13 filed capacity rates.

14 Staff developed capacity payments for QFs offering power starting
15 in 1994 based upon deferral of the next power plant planned by each
16 utility, assuming contracts of various lengths and considering whether
17 the QF wants payments to begin in 1994 (up-front payments) or is
18 willing to wait for capacity payments until the year the utility would
19 otherwise need to add capacity. Under Staff's proposal, the present
20 value of capacity payments should equal the present value of the
21 deferral of capacity costs. Staff recommended that the Companies
22 submit values for capacity payments for Staff review and approval
23 using the principles underlying the values in Staff Report Table 4,
24 page E-52, within six months from the effective date of this Decision.
25 The values in the Table (or Staff updates of these values) would be
26 used if the utility does not submit the capacity values.³¹

27 ³¹ AEPCO has taken exception to the use of the next avoided
28 unit as the basis for calculating capacity payments. If the
Utilities have a method of calculation for capacity payments that

1 We shall adopt Staff's recommendations regarding capacity
2 payments for purchases from QFs over 100 kw. Additionally, we shall
3 require that the Companies include in their filings maximum payments
4 for energy from QFs over 100 kw reflecting avoided fuel and variable
5 operating and maintenance costs, considering system conditions, and
6 the characteristics of QF power. These maximum payments may be
7 adjusted from time to time and may be reduced in the course of
8 individual contract negotiations.

9 Intervenor Schmidt presented evidence regarding global warming.
10 Mr. Schmidt recommended that the Commission order the Companies to
11 provide a carbon dioxide mitigation scenario with their next IRP
12 filings. We agree that global warming due to increasing levels of
13 greenhouse gases and carbon dioxide is an important environmental and
14 societal issue and encourage the Companies to consider the impact of
15 such in their next IRP filings. Further, consideration of any such
16 impact(s) should be consistent with the findings and guidelines
17 developed by the Externalities Prioritization Working Group pursuant
18 to Decision No. 57589 and any subsequent rules.

19 IV. Load Forecasting

20 The Staff Report found (and no party disputed) that load
21 forecasting is a pivotal element of IRP. The load forecast drives the
22 selection of supply and demand side resources over the planning
23 horizon. However, any forecast, especially one that makes predictions
24 twenty years into the future, may be in error. Hence, the Companies
25 sometimes make a range of forecasts to develop a flexible set of plans
26 to deal with uncertainty about the future.

27
28 _____
differs from the underlying principals presented by Staff, they may
submit such method to Staff for approval.

1 Staff developed a set of load forecasts as an independent check
2 on the Companies' forecasts. The purpose of the Staff forecasts is
3 not to argue that one forecast is right and the other wrong, but to
4 ascertain whether the base case forecasts of the Companies are
5 reasonable given forecasts on population, employment, and other
6 factors and given historical trends in factors affecting the demand
7 for electricity. If the Staff forecasts are consistent with the
8 Companies' forecasts, it can be inferred that there are no readily
9 apparent factors that we expect would cause utility demand to greatly
10 deviate from forecasted future demand. If the Staff forecasts are not
11 consistent with the Companies' forecasts, it can be inferred that at
12 least one set of forecasts has not properly considered available
13 information or that the utility is facing a very uncertain future.

14 In this Docket, the Companies' long range forecasts of retail MW
15 demand show that growth rates are expected to average between 2 and 3
16 percent per year between 1993 and 2002, except for Citizens, which
17 expects an average annual growth rate of 3.9 percent. Staff concluded
18 that APS', TEP's,³² SRP's, AEPCO's and Citizens'³³ forecasts are
19 consistent with Staff's forecasts through about 2002. No party
20 disputed Staff's conclusions.

21 We find that Staff's load forecasts are consistent with the
22 Companies' forecasts for the next ten years, given uncertainties about

23 ³² TEP's forecast assumes that additional mining operations
24 will add new loads between 1993 and 1997. Staff Forecast A for TEP
25 includes additional mining loads and is comparable to TEP's
26 forecast. However an alternative forecast should also be considered
27 that reflects the uncertainty associated with the timing of mining
28 additions. Staff Forecast B assumes that no significant mining
additions occur during the forecast period.

³³ It appears that Citizens' growth is considerably higher
than the other utilities due to continued high customer growth in
the Mohave area.

1 electricity demand in the mining sector. In particular, there is some
2 uncertainty about demand in TEP's service area due to uncertainty
3 about the dates when additional mining loads may come into existence.
4 Because TEP is not planning to add any supply side resources until
5 2002, there is no immediate practical effect of possible errors in
6 demand forecasts that cannot be rectified in future load forecasts and
7 resource plans as more information becomes available. Additionally,
8 there is considerable uncertainty regarding AEPCO's future load
9 because of uncertainty about mining loads. To a large extent, AEPCO's
10 member cooperatives must manage that uncertainty as they negotiate
11 special contracts with mining customers.

12 We also agree with Staff with respect to the difficulties of
13 implementing forecasting models that rely upon end use data. Such
14 models can provide additional insight into load growth. For such a
15 model to be most useful, however, detailed data is required. We will,
16 therefore, require the Companies to increase their collection of end
17 use load data, to obtain commercial and industrial energy sales data
18 by Standard Industrial Classification ("SIC") category, and to collate
19 that information with data on commercial and industrial customers such
20 as number of employees in each SIC category. The ability to forecast
21 demand for commercial and industrial customers depends on having such
22 disaggregated data. We will also require that the Companies
23 coordinate with Staff their efforts to collect the data described
24 above and that the Companies include this data in their annual IRP
25 data filings, beginning with their next filing.

26 V. Administrative Matters

27 After reviewing the Plans for both 1989 and 1992, Staff believes
28 several generic improvements can be made. In particular, Staff

proposed the following features for future Plans filed with the Commission:

- ♦ the Plan should have a comprehensive, self-explanatory load and resources table summarizing the utility's Plan;
- ♦ the Plan should have an easy-to-read, brief executive summary that will inform the public about the utility's Plan and the load and resources table should be included in the executive summary. The executive summary can be provided to people requesting copies of the Plan instead of copying voluminous technical information that is of little value to individuals interested in a non-technical report;
- ♦ voluminous computer output is discouraged; it is usually incomprehensible, it needs interpretation, and it wastes paper;
- ♦ the Plan should be in the form of a narrative leading the reader to logical conclusions and supported by tables, graphs, charts, etc;
- ♦ the Plan should be indexed to indicate where the filing requirements can be found (see APS' Plan for an example);
- ♦ terms should be defined as they are used by the utility; for example, utilities use the term "forced outage rate" differently and it is not always clear whether demand includes or excludes sales for resale; and
- ♦ the Companies should strive for consistency in data and assumptions throughout their Plans.

As there was no opposition to these recommendations and because these recommendations will improve the readability and usefulness of the Plans, we will adopt them herein.

VI. Summary

Based upon the record in this proceeding and the foregoing analysis, we find that Plans submitted are generally consistent with the IRP requirements set forth in A.A.C. R14-2-701 et seq. Further, the record establishes that additional requirements should be imposed on the respective parties in the manner set forth hereinbelow.

* * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. APS, TEP, AEPCO, and Citizens (collectively "Companies") are certificated to provide electric utility service to the public in portions of Arizona pursuant to authority granted by the Commission.

2. SRP is an agricultural improvement district duly organized and existing under Title 48, Chapter 17 of the laws of the State of Arizona, and is a political subdivision of the State of Arizona pursuant to Article 13, section 7 of the Arizona Constitution. SRP is principally engaged in the generation of electricity in the States of Arizona, New Mexico, Nevada and Colorado, and the purchase and sale of electricity to customers in Maricopa, Pinal, and Gila Counties in the State of Arizona.

3. Southwest Gas is a California corporation engaged in the business of providing natural gas utility service to the public in portions of Arizona pursuant to the authority granted by the Commission.

4. ACAA is an Arizona non-profit organization that helps low-income people become self sufficient.

5. The LAW Fund is a western regional environmental organization committed to reducing the environmental impacts associated with meeting the need for utility energy services.

6. Pursuant to A.A.C. R14-2-703, the Companies filed their respective 1992 Plans.

7. Pursuant to A.A.C. R14-2-704.A, the Commission must schedule a hearing to review the Companies' Plans and to evaluate those Plans

1 in light of analyses by Staff and others within 120 days of the filing
2 dates.

3 8. SRP agreed to participate in the IRP process on a voluntary
4 basis and filed its Plan.

5 9. Pursuant to the September 9, 1993 Procedural Order, this
6 matter was set for hearing commencing on December 7, 1993.

7 10. Intervention in this matter was granted to RUCO, SRP,
8 Southwest Gas, ACAA, the LAW Fund, Phelps Dodge Corporation, Don't
9 Waste Arizona, Inc., Cyprus Mineral Company, and Mr. Lothar M.
10 Schmidt.

11 11. Workshops were held on October 8, 18, 19 and 20, 1993 at the
12 Commission's offices.

13 12. The hearing commenced on December 7, 1993.

14 13. The purpose of IRP is to minimize the total societal cost of
15 meeting the demand for electric energy services giving due
16 consideration to ratepayer impacts, utility financial health and
17 economic growth within a utility's service area.

18 14. The goal of resource planning can be achieved by finding the
19 mix of supply and demand side resources that minimize society's costs.

20 15. Electric utilities are coming under increasing competitive
21 pressure to keep prices to their customers low. Impacts on the
22 competitive position of Arizona's utilities warrant specific
23 consideration in the development and implementation of IRPs.

24 16. DSM is the systematic effort to improve the efficiency of
25 using electric energy and power.

26 17. DSM is cost-effective if reductions in power usage at peak
27 production times for the utility and reductions in energy usage at any
28 time are less costly to society than generating, transmitting, and

1 distributing electricity, including building of any new generation,
2 transmission, or distribution capacity.

3 18. The Commission has established a cost recovery mechanism for
4 DSM programs for APS, TEP, Citizens, AEPCO, and several distribution
5 cooperatives.

6 19. To be eligible for the cost recovery mechanism, a DSM
7 program must be pre-approved by the Commission Staff.

8 20. The Companies' projections indicate that sales will be
9 reduced by about 1160 MW by the year 2010 as a result of DSM
10 undertaken between 1993 and 2010.

11 21. Cost-effective residential retrofit programs aimed at low-
12 income customers would be consistent with the basic purpose of IRP
13 which is to meet the demand for electric energy services at minimum
14 cost.

15 22. Monitoring of DSM programs serve several purposes: to
16 determine participation rates and kw and kwh savings; to provide a
17 foundation for recovery of lost net revenues and incentives to the
18 utility based on kw or kwh savings (if authorized by the Commission);
19 to evaluate the process by which the utility implements its DSM
20 programs; and to provide information on whether to continue, modify,
21 or terminate a program.

22 23. As a potential addition to the menu of DSM programs offered
23 by the Companies, the Companies should consider a design team approach
24 to new commercial buildings to encourage the construction of energy
25 efficient new buildings.

26 24. The Companies must first offer and promote cost effective
27 energy efficiency measures when negotiating special contracts that
28 offer discounted rates to attract or retain a business.

1 25. A Staff directed DSM workshop on the topic of repayment of
2 incentives out of savings is necessary and such a workshop should
3 include consideration of the bonus payment proposal by the LAW Fund.

4 26. The Companies, especially TEP and APS, should increase their
5 respective DSM activities and accelerate DSM targets in the next IRP
6 filing.

7 27. If the Companies do not accelerate their DSM activities,
8 specific targets should be considered in future IRP hearings.

9 28. There should be no specific targets for low-income programs,
10 but APS should begin a low-income pilot program with potentially cost
11 effective DSM measures and then, after one year, modify the program as
12 appropriate.

13 29. TEP should use the results of its current low-income program
14 to develop a larger, cost-effective low-income DSM program.

15 30. The Companies should consider in their next IRP filing
16 whether fuel switching as a DSM resource potential is an option.

17 31. Within twelve months from the effective date of this
18 Decision, each of the Companies must solicit from parties to this
19 Docket (and other interested parties who make themselves known to the
20 utility) specific proposals for DSM measures, programs, and screening
21 prior to preparing its Plan for the next required IRP filing and
22 conduct a workshop (or workshops if more than one workshop is needed)
23 on its DSM proposals. Staff should coordinate and establish a
24 schedule for such workshops. The schedule for the workshops should
25 allow sufficient time for the parties to ask the Companies for
26 information relevant to the DSM programs.

27 32. The proposed workshop for each utility described in the
28 above finding will promote greater public participation in the DSM

1 planning process without removing from the Companies their
2 responsibilities to develop and implement DSM programs and without
3 removing from Staff its responsibilities to review those programs.
4 The parties to the workshops should discuss the relative merits of
5 ~~expensing~~ versus capitalizing DSM program costs and net lost revenues.

6 33. Although the Companies prepare regular reports to Staff on
7 progress with their DSM programs, some parties have not found these
8 reports easy to obtain.

9 34. Each utility should file one copy of its DSM reports with
10 the Commission's Docket Control for better public access.

11 35. In order for interested parties to have more direct input
12 into the DSM recovery process, Companies that file for pre-approval of
13 DSM programs for which recovery is sought should file a notice of such
14 filing and a copy of such plan with the Commission's Docket Control
15 and notify all interested parties of the filing. Interested parties
16 shall then have 20 days to file any written comments with Staff.

17 36. Upon Staff's pre-approval, Staff shall submit the projects
18 to the Commission for its consideration and preliminary adoption and
19 if the Commission adopts the pre-approval, the projects shall be
20 considered approved for cost-recovery in future rate proceedings. The
21 Commission, however, reserves the right to review the projects in
22 future rate proceedings, if necessary, to make a final determination
23 with respect to the appropriateness of the cost-recovery.

24 37. Utility progress on M&E evaluation is hard to judge since
25 monitoring efforts are still underway.

26 38. Evaluation of kw and kwh savings should be conducted using
27 state-of-the-art methods in a competent, scientific manner; data and
28

1 results should provide a comprehensive, internally consistent account
2 of the savings from DSM.

3 39. Advertising appears to be growing in importance as a cost
4 element of DSM programs. The Companies should include in pre-approval
5 filings a monitoring plan for advertising for each DSM program whose
6 advertising costs are budgeted to exceed \$100,000 per year for AEPCO
7 and Citizens and \$300,000 for TEP and APS.

8 40. The Companies should measure the impact of free ridership
9 and free drivers on the level of savings associated with their DSM
10 programs in cases where such effects are likely to be important and
11 significantly influence the cost-effectiveness of a DSM program.

12 41. The review of M&E of DSM should be a public process and APS,
13 TEP, AEPCO, and Citizens should each make an annual presentation at
14 workshops covering the following topics:

- 15 ♦ study designs for DSM programs for which monitoring is
16 required (as indicated in Staff's pre-approval letter) and
for which monitoring has not yet begun or is about to begin
(including process evaluations);
- 17 ♦ progress reports on M&E projects underway (including process
18 evaluations); and
- 19 ♦ results from M&E projects that have been completed during
20 the previous year or are near completion (including process
evaluations).

21 42. Financial barriers to DSM have led the Commission to develop
22 mechanisms for program cost recovery, recovery of lost net revenues,
23 and recovery of a profit or reward to make the utility indifferent
24 between traditional supply side resources and DSM.

25 43. Currently, APS has a \$4 million cap in place on recovery of
26 DSM costs.

27 44. In TEP's recent rate case, cost recovery is limited in
28 magnitude by TEP's plans as of the time of the rate case hearing.

1 45. A deferred accounting approach should be adopted in which
2 APS and TEP (and any other utility desiring a deferred accounting)
3 should file an application for Commission approval which contains: a
4 DSM savings target; a specific DSM program consisting of cost-
5 effective DSM measures; an effective M&E plan; and a program designed
6 to manage revenue impacts to the utility and ratepayers.

7 46. It would be useful for parties to this Docket to meet
8 publicly with APS and TEP in workshops (prior to the Companies' filing
9 for Commission approval of specific accounting authority) to discuss
10 how the deferred accounting would work and to consider the rate
11 impacts of the proposed level of deferrals.

12 47. For costs in excess of those included in base rates or
13 existing capped surcharges, deferred accounting is appropriate if
14 ratepayers have a reasonable probability of getting the savings DSM
15 programs can provide.

16 48. Costs to be included in the deferral account are program
17 costs (e.g., administrative costs, rebates, M&E costs, etc.) and lost
18 net revenues, (if already authorized) and, if already authorized, a
19 reward for deferring the return on capacity additions deferred by DSM.

20 49. Costs may only be entered into the deferral account if they
21 are associated with programs pre-approved by Staff and when kw and kwh
22 savings are reasonably probable and can be analyzed and measured using
23 monitored data (following a public review of the analysis in the
24 annual workshops on M&E).

25 50. Program costs may be entered in the deferral account if they
26 are associated with monitored pre-approved educational or research
27 programs from which no kwh or kw savings can be practically derived.

28 51. Costs included in the deferral account may be recovered at

1 the next rate case, possibly amortized over several years because of
2 their potentially large magnitude.

3 52. Consistent with Decision No. 57589, deferred amounts may
4 accrue interest at the approved cost of capital of the utility.

5 — 53. The Commission encourages the parties to bring forth
6 innovative ideas on how to unlink revenues and sales in future IRP
7 proceedings.

8 54. The Commission will consider incentives for DSM that focus
9 on recovery of program costs, recovery of lost net revenues, and, if
10 appropriate, recovery of a reward for deferring returns on future
11 capacity.

12 55. The Commission has considered the new PURPA standards
13 regarding IRP in the Energy Policy Act of 1992 through its IRP rules
14 (A.A.C. R14-701 et seq.) which have been in effect since 1989, and
15 through rate case decisions.

16 56. Arizona's IRP process meets the requirements of 40 CFR 73.82
17 (a)(4) and (a)(6) regarding allowances from the Conservation and
18 Renewable Energy Reserve.

19 57. The benefits to the Companies with regard to gaining
20 additional sulfur dioxide allowances should be considered in rate
21 cases when determining whether to allow the utility to recover lost
22 net revenues or rewards for DSM savings.

23 58. There is nothing that precludes a utility from filing for
24 approval for recovery of high efficiency HVAC programs.

25 59. Between 1993 and 2010, the Companies plan to add
26 approximately 2285 MW of new generating capacity at a cost (present
27 value) of \$812 million.
28

60. Most of the planned capacity to be added between 1993 and 2010 is gas-fired.

61. Combined cycle units comprise nearly half of the planned additions, combustion turbines account for about 25 percent of the new capacity, baseload units comprise 15 percent of the new capacity and the remainder consists of increasing the capacity of existing plants (uprating) and the use of other technologies, including 10 MW of photovoltaics and 2 MW of fuel cell production.

62. Common forms of renewable energy resources include: photovoltaics; solar thermal resources such as parabolic troughs, parabolic dishes, and central receivers; windpower; biomass consisting of wood, wood waste, agricultural waste, municipal solid waste, and landfill and digester gas; geothermal resources, including hydrothermal resources and hot dry rock; and hydropower.

63. A working group consisting of Staff and utility planners (as well as any other parties to this Docket who wish to participate) should be created to develop a framework (or frameworks) to thoughtfully handle uncertainty in supply side IRP decisions, and to complete a discussion paper within one year that collaboratively develops:

- ♦ a better understanding of how to evaluate the risks and benefits of gas-fired plants and renewable resources (with emphasis on solar thermal plants and possibly windpower), by inviting experts on decision analysis, solar and wind technology, and conventional technology to make presentations;
- ♦ A decision analysis of a generic combined cycle unit, a generic solar plant, and possibly a generic wind plant for the purpose of improving the parties' understanding of how to do such an analysis; and
- ♦ Suggestions on how the Companies should analyze the risks and benefits of renewables and conventional technology in their next Plans.

1 64. Staff should coordinate the working group's activities;
2 details of the procedures used by the working group should be
3 determined by the participants at the beginning of the process.

4 65. Staff recommended flexible, long-term, set asides for
5 renewable resources of 40 MW each for AEPCO and Citizens, and set
6 asides of 160 MW for APS and TEP to be added by 2009.

7 66. The Companies believe that Staff's proposal for set asides
8 is premature and that additional study is needed before committing to
9 renewables.

10 67. The time is ripe for serious consideration of renewables
11 over the long run, well beyond the efforts described in the Companies'
12 Plans.

13 68. Before the Commission imposes long-term set asides, there
14 needs to be additional notice and opportunity for the Companies and
15 other interested parties to be able to respond to, and conduct
16 additionally study and planning for, such a requirement.

17 69. We will require that establishing the appropriate long-term
18 goals for the year 2009 become a topic of the working group (discussed
19 hereinabove) and part of the discussion paper that will be submitted
20 to the Commission. Both MW and MWH goals should be a topic of
21 discussion at the workshop and in the discussion paper.

22 70. The LAW Fund has recommended that the Commission direct the
23 Companies to develop comprehensive renewable resource plans as part of
24 their next IRP filing that aim at capturing the full potential of
25 renewable resources to serve electricity needs. Such comprehensive
26 plan should contain the following key elements:

- 27 ♦ developing an information base on renewable resources on
28 which Arizona utilities may rely;

- ♦ providing for a sustained, focused research, development, and demonstration effort aimed at preparing the way for the utilization of viable renewable resource technologies;
- ♦ assuring that IRPs developed by utilities in Arizona take advantage of renewables;
- ♦ proposals for fine tuning the Commission's regulatory policies so that they encourage utility renewable resource initiatives that are consistent with the first three elements; and
- ♦ evidence that the Companies are tapping the increasing federal funding support for renewable resources.

71. We concur with the LAW Fund that the Companies should include the above elements in their next IRP filings.

72. If by the next IRP filing, the respective Companies do not propose in their Plans reasonable alternatives to Staff's recommendations regarding the set asides, the Commission will reconsider Staff's recommendations regarding long-term set asides to be implemented by the year 2009.

73. Staff has recommended that, at a minimum, the Plans due to be filed by December 31, 1995 include the following mandatory targets for renewables to be implemented not later than December 31, 2000:

AEPCO	1,000 kw ³⁴
Citizens	1,000 kw
TEP	5,000 kw
APS	12,000 kw

74. Under Staff's proposal, the Companies should be allowed to credit renewable energy systems installed between January 1, 1993 to December 31, 2000 toward the short-term goal.

75. The intent of the short-term set asides is to enhance learning about renewables to prepare for larger efforts after 2000.

³⁴ In the case of AEPCO, projects undertaken by member cooperatives can be counted toward the goal.

1 76. The short-term set asides may be counted toward any long-
2 term set aside goals that may be ordered in the future.

3 77. APS indicated that it is willing to strive toward a goal of
4 12 MW for renewables by 2000 and TEP indicated that it is willing to
5 strive toward a goal of 5 MW for renewables by 2000.

6 78. These are serious commitments and should be considered
7 planning goals which are predicated upon articulated assumptions. If,
8 however, APS and TEP appear to fall significantly short of meeting
9 these goals, short-term set asides should be reconsidered. If
10 assumptions in setting these goals do not materialize, the goals may
11 be revisited and modified in keeping with the facts known at such
12 time.

13 79. As for Citizens and AEPCO, the short-term set asides of 1 MW
14 each are reasonable and these set asides should also be considered
15 planning goals for the year 2000.

16 80. The Companies should use the nameplate rating of a renewable
17 generating resource when crediting a resource toward the set aside;
18 this procedure is administratively easier than trying to devise
19 methods to make renewable capacity equivalent to combined cycle or
20 combustion turbine capacity and it reflects the fact that renewables
21 may be produced in ways not directly comparable to conventional
22 central station generators.

23 81. The Companies are encouraged to consider RFPs for renewables
24 as a means of implementing the short-term goals and possible long-term
25 set asides that may be required in the future.

26 82. Each of the Companies should develop a data base of existing
27 renewable energy resources within its system within six months from
28 the effective date of this Decision; these inventories should be

1 revised annually and submitted to Staff each year as part of the
2 historical data filings required under the IRP rules.

3 83. Each of the Companies should prepare a three year renewable
4 resource action plan as part of its filing requirements for an action
5 plan under the Commission's IRP rules, starting with the Plans to be
6 submitted by December 31, 1995.

7 84. The Companies should include in their IRP Plans (to be filed
8 by December 31, 1995) explicit discussions of their research and
9 development plans and activities regarding renewables, including
10 descriptions of projects undertaken and costs of those projects.

11 85. Consideration should be given in rate cases of allowing cost
12 recovery for prudent investments in renewable generation demonstration
13 projects (such as Solar Two), whose purpose is to better determine the
14 costs and output potential of the technology.

15 86. The Companies should recover prudent costs of set aside
16 renewable resources (within limits on the cost per kw to be determined
17 in future rate cases) after Commission consideration of utility cost
18 estimates and proposals for cost recovery; the criteria for
19 determining the limits on costs should include: estimates of costs
20 from engineering studies or field experience; the costs of other
21 (alternative) renewable technologies; the degree to which
22 commercialization of the technology has progressed; and the likelihood
23 that the proposed technology can be cost effective in the future (if
24 not currently cost effective)³⁵.

25 87. The Commission's policy stated in Decision No. 57589
26 concerning the provision of information on photovoltaics to potential

27 ³⁵ The proposed technology must reasonably be expected to
28 show cost effectiveness as soon as practical, but in no event longer
than 10 years from the date the utility requests recovery.

1 line extension customers in remote areas, based on Staff guidelines,
2 should be continued.

3 88. Proposals that renewable capacity may be put into rate base
4 and earn a return shall be considered in rate cases.

5 — 89. The Companies may consider Green Pricing Programs and the
6 Companies may discuss this in their next IRP filing.

7 90. Competitive bidding may be used to obtain utility resources,
8 but such bidding processes should be founded on a thorough
9 understanding of transaction costs so that contracts can be written
10 which result in power and energy when needed at reasonable cost
11 without unduly transferring risks to the utility or the ratepayer.

12 91. The Companies who wish to engage in supply or demand side
13 competitive bidding should inform Staff of all requests for bids at
14 least 45 days prior to issuing the request and submit to Staff a
15 complete report on the bids, the utility's evaluation of the bids, and
16 the utility's selection of the winner(s) no more than 30 days after
17 selecting winning bids.

18 92. Staff should continue to participate in SWRTA meetings on a
19 regular basis to keep informed of transmission planning issues.

20 93. The Companies should include in future Plans explicit
21 analyses of the changes in their transmission and distribution plans
22 and associated savings attributable to DSM programs.

23 94. With regard to EWGs in Decision No. 58424 (October 14,
24 1993), we declined to adopt the Section 712 standards and we reaffirm
25 our position.

26 95. Under PURPA, utilities are obligated to purchase energy and
27 power from qualifying cogenerators and small power producers at rates
28 up to the utility's avoided costs.

1 96. Staff developed capacity payments for Qfs offering power
2 starting in 1994 based upon deferral of the next power plant planned
3 by each utility, assuming contracts of various lengths and considering
4 whether the QF wants payments to begin in 1994 (up-front payments) or
5 ~~is~~ willing to wait for capacity payments until the year the utility
6 would otherwise need to add capacity.

7 97. The present value of capacity payments should equal the
8 present value of the deferral of capacity costs.

9 98. The Companies should submit values for capacity payments to
10 QFs over 100 kw for Staff review and approval using the principles
11 underlying the values in Staff Report Table 4, page E-52, within six
12 months from the effective date of this Decision; the values in the
13 Table (or Staff updates of these values) would be used if the utility
14 does not submit the required capacity values.

15 99. The Companies should include in their filings maximum
16 payments for energy from QFs over 100 kw reflecting avoided fuel and
17 variable operating and maintenance costs, considering system
18 conditions, and the characteristics of QF power. These maximum
19 payments may be adjusted from time to time and may be reduced in the
20 course of individual contract negotiations.

21 100. Because AEPCO's member cooperatives make arrangements with
22 QFs, we will also require that, after Staff has determined that
23 AEPCO's buyback rates for QFs over 100 kw are in compliance (or that
24 the Staff values should be used), AEPCO should file jointly with each
25 of its Arizona member cooperatives appropriate buyback rates that will
26 be paid by the member cooperatives to QFs over 100 kw.

101. Because deferred capacity costs and avoided energy costs will vary over time, the Companies should revise their buyback rates accordingly.

102. The possibility of global climate change due to increasing levels of greenhouse gases is an important environmental and societal issue. Thus, the Companies are encouraged to consider the impact of this issue in their next IRP filings. Consideration of any such impact(s) should be consistent with the findings and guidelines developed by the Externalities Prioritization Working group pursuant to Decision No. 57589 and any subsequent rules.

103. The Companies' long range forecasts of retail MW demand show that growth rates are expected to average between 2 and 3 percent per year between 1993 and 2002, except for Citizens, which expects an average annual growth rate of 3.9 percent.

104. Staff's load forecasts are consistent with the Companies' forecasts for the next ten years, given uncertainties about electricity demand in the mining sector.

105. Models which use end use data can provide additional insight into load growth; however, for such models to be most useful, detailed data is required.

106. The Companies should increase their collection of end use load data, obtain commercial and industrial energy sales data by Standard Industrial Classification (SIC) category, and collate that information with data on commercial and industrial customers such as number of employees in each SIC category.

107. The Companies should coordinate with Staff their efforts to collect the data described above and must include the data described above in their next annual IRP data filings.

108. To improve Plans we shall require the following features in all future IRP filings:

- ◆ each Plan should have a comprehensive, self-explanatory load and resources table summarizing the utility's Plan;
- ◆ each Plan should have an easy-to-read, brief executive summary that will inform the public about the utility's plan; the load and resources table should be included in the executive summary;
- ◆ voluminous computer output is discouraged; it is usually incomprehensible, it needs interpretation, and it wastes paper;
- ◆ the Plan should be in the form of a narrative leading the reader to logical conclusions and supported by tables, graphs, charts, etc.;
- ◆ each Plan should be indexed to indicate where the filing requirements can be found (see APS' plans for an example);
- ◆ terms should be defined as they are used by the utility; and
- ◆ the Companies should strive for consistency in data and assumptions throughout their Plans.

CONCLUSIONS OF LAW

1. APS, TEP, AEPCO and Citizens are Arizona public service corporations within the meaning of Article XV of the Arizona Constitution.

2. The Commission has jurisdiction over APS, TEP, AEPCO, Citizens, and Southwest Gas and over the subject matter of the Plans.

3. A.A.C. R14-2-703.F requires each electric utility under the Commission's jurisdiction which operates or owns generating facilities to file with the Commission a Plan every three years.

4. A.A.C. 14-2-704.A requires the Commission to schedule a hearing to review the Plans and to determine the degree of consistency between these Plans and the analyses conducted by Staff and other parties within 120 days of the submission of the Plans.

5. The Plans submitted by APS, TEP, AEPCO and Citizens are consistent within the meaning of A.A.C. R14-2-704.

6. The parties to this proceeding should comply with the requirements set forth hereinbelow.

ORDER

IT IS THEREFORE ORDERED that the 1992 Integrated Resource Plans submitted by Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company are hereby consistent in accordance with A.A.C. R14-2-704.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall either develop a design team approach to new commercial buildings to encourage the construction of energy efficient new buildings, or indicate in their regular reports on DSM programs, within one year from the effective date of this Decision, why design teams are not appropriate.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall first offer and promote cost effective energy efficiency measures when negotiating special contracts that offer discounted rates to attract or retain a business.

IT IS FURTHER ORDERED that Staff shall undertake a workshop on repayment programs, including the Land and Water Fund of the Rockies' bonus program.

IT IS FURTHER ORDERED that Arizona Public Service Company shall begin a low-income pilot program with potentially cost-effective DSM measures and then, after one year, modify the program as appropriate.

1 IT IS FURTHER ORDERED that Tucson Electric Power Company shall
2 use the results of its current low-income program to develop a larger,
3 cost-effective low-income DSM program.

4 IT IS FURTHER ORDERED that within twelve months of the
5 Commission's decision in each IRP review, each utility shall solicit
6 from parties to this Docket (and other interested parties who make
7 themselves known to the utility) specific proposals for DSM measures,
8 programs, and screening prior to preparing its Plan for the next
9 required filing and conduct a workshop, as coordinated by Staff, on
10 DSM proposals.

11 IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson
12 Electric Power Company, Arizona Electric Power Cooperative, and
13 Citizens Utilities Company shall consider in their next IRP filing
14 whether fuel switching as a DSM resource potential is an option.

15 IT IS FURTHER ORDERED that each utility shall file one copy of
16 its DSM reports with the Commission's Docket Control.

17 IT IS FURTHER ORDERED that each utility that files for pre-
18 approval of a DSM program shall file a notice of such filing and a
19 copy of such plan with the Commission's Docket Control and shall
20 notify all interested parties (as defined in the Discussion
21 hereinabove) of the filing; such interested parties shall then have 20
22 days to file any written comments with Staff to be taken into
23 consideration.

24 IT IS FURTHER ORDERED that upon Staff's pre-approval, Staff shall
25 submit the projects to the Commission for its consideration and
26 preliminary adoption and if the Commission adopts the pre-approval,
27 the projects shall be considered for cost-recovery in future rate
28 proceedings.

1 IT IS FURTHER ORDERED that the Commission reserves the right to
2 review pre-approved projects in future rate proceedings, if necessary,
3 to make a final determination with respect to the appropriateness of
4 the cost-recovery.

5 — IT IS FURTHER ORDERED that evaluation of kw and kwh savings shall
6 be conducted using state-of-the-art methods in a competent, scientific
7 manner; data and results should provide a comprehensive, internally
8 consistent account of the savings from DSM.

9 IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson
10 Electric Power Company, Arizona Electric Power Cooperative, and
11 Citizens Utilities Company shall include in pre-approval filings a
12 monitoring plan for advertising for each DSM program whose advertising
13 costs are budgeted to exceed \$100,000 for AEPCO and Citizens and
14 \$300,000 for APS and TEP, and for advertising costs less than that
15 amount, such expenditures should be supported by explaining the
16 objective, intended target audience, estimated costs and intended
17 media.

18 IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson
19 Electric Power Company, Arizona Electric Power Cooperative, and
20 Citizens Utilities Company shall measure the impact of free ridership
21 and free drivers on the level of savings associated with their DSM
22 programs in cases where such effects are likely to be important and
23 significantly influence the cost-effectiveness of a DSM program.

24 IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson
25 Electric Power Company, Arizona Electric Power Cooperative, and
26 Citizens Utilities Company shall each make an annual presentation at
27 workshops covering the following topics:
28

- 1 ♦ study designs for DSM programs for which monitoring is
2 required (as indicated in Staff's pre-approval letter) and
3 for which monitoring has not yet begun or is about to begin
4 (including process evaluations);
- 5 ♦ progress reports on M&E projects underway (including process
6 evaluations); and
- 7 ♦ results from M&E projects that have been completed during
8 the previous year or are near completion (including process
9 evaluations).

10 IT IS FURTHER ORDERED that Arizona Public Service Company and
11 Tucson Electric Power Company shall file for approval of an accounting
12 order to defer DSM costs in excess of those included in base rates or
13 existing capped surcharges.

14 IT IS FURTHER ORDERED that the applications for deferred
15 accounting shall include DSM savings targets, monitoring plans, cost-
16 effective DSM measures, and program designs to manage the costs of
17 DSM.

18 IT IS FURTHER ORDERED that program costs, lost net revenues (if
19 authorized), and a reward (if already authorized), shall be entered
20 into the deferral account if they are associated with programs pre-
21 approved by Staff and when kw and kwh savings have been demonstrated
22 using monitored data (following a public review of the analysis in the
23 annual workshops on M&E); additionally, program costs may be entered
24 in the deferral account if they are associated with monitored pre-
25 approved educational or research programs from which no kw or kwh
26 savings can be practically derived.

27 IT IS FURTHER ORDERED that workshops on proposed deferred
28 accounting shall be held prior to a utility filing for deferred
29 accounting related to its DSM programs.

1 IT IS FURTHER ORDERED that the Commission has hereby considered
2 the new PURPA standards through its IRP rules (A.A.C. R14-701 et seq.)
3 which have been in effect since 1989 and through rate case decisions.

4 IT IS FURTHER ORDERED that the IRP process hereby meets the
5 criteria for obtaining Conservation and Renewable Energy Reserve
6 allowances.

7 IT IS FURTHER ORDERED that the benefits to Arizona utilities with
8 regard to gaining additional sulfur dioxide allowances shall be
9 considered in rate cases when determining whether to allow the utility
10 to recover lost net revenues or rewards for DSM savings.

11 IT IS FURTHER ORDERED that nothing herein shall be considered to
12 preclude a utility from filing for approval for recovery of high
13 efficiency HVAC programs.

14 IT IS FURTHER ORDERED that a working group consisting of Staff
15 and utility planners (as well as any other parties to this Docket who
16 wish to participate) shall be created to develop a framework (or
17 frameworks) to thoughtfully handle uncertainty in supply side IRP
18 decisions (including setting the appropriate level of long-term
19 goals), to complete a discussion paper within one year, and to
20 collaboratively develop:

- 21 ♦ a better understanding of how to evaluate the risks and
22 benefits of gas-fired plants and renewable resources (with
23 emphasis on solar thermal plants and possibly windpower), by
24 inviting experts on decision analysis, solar and wind
25 technology, and conventional technology to make
26 presentations;
- 27 ♦ a decision analysis of a generic combined cycle unit, a
28 generic solar plant, and possibly a generic wind plant for
the purpose of improving the parties' understanding of how
to do such an analysis; and
- ♦ suggestions on how the Companies should analyze the risks
and benefits of renewables and conventional technology in
their next Plans.

1 IT IS FURTHER ORDERED that the appropriate long-term goals for
2 the year 2009 become a topic of the working group and part of the
3 discussion paper that will be submitted to the Commission.

4 IT IS FURTHER ORDERED that in the absence of viable alternatives,
5 ~~Arizona Public Service Company, Tucson Electric Power Company, Arizona~~
6 ~~Electric Power Cooperative, and Citizens Utilities Company, shall~~
7 ~~incorporate into their future Plans (and undertake commensurate~~
8 ~~research, development, commercialization, and implementation~~
9 ~~activities) appropriate levels of renewables.~~

10 IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson
11 Electric Power Company, Arizona Electric Power Cooperative, and
12 Citizens Utilities Company, shall develop comprehensive renewable
13 resource plans as part of their next IRP filing that aim at capturing
14 the potential of renewable resources to serve electricity needs that
15 include the following:

- 16 ♦ developing an information base on renewable resources on
17 which Arizona utilities may rely;
- 18 ♦ providing for a sustained, focused research, development,
19 and demonstration effort aimed at preparing the way for the
20 utilization of viable renewable resource technologies;
- 21 ♦ assuring that IRPs developed by utilities in Arizona take
22 advantage of renewables;
- 23 ♦ proposals for fine tuning the Commission's regulatory
24 policies so that they encourage utility renewable resource
25 initiatives that are consistent with the first three
26 elements; and
- 27 ♦ evidence that the Companies are tapping the increasing
28 federal funding support for renewable resources.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson
Electric Power Company, Arizona Electric Power Cooperative, and
Citizens Utilities Company shall strive for installing and operating

the following amounts of renewable capacity not later than December 31, 2000:

Arizona Electric Power Cooperative	1,000 kw ³⁶
Citizens Utilities Company	1,000 kw
Tucson Electric Power Company	5,000 kw
Arizona Public Service Company	12,000 kw

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall be permitted to credit renewable energy systems installed between January 1, 1993 to December 31, 2000 toward the goal for the year 2000.

IT IS FURTHER ORDERED that renewables installed and operated by the year 2000 shall be counted toward any renewable capacity values established in future IRP proceedings.

IT IS FURTHER ORDERED that if any utility appears to fall significantly short of meeting the year 2000 renewables goals, the Commission may reconsider short-term set asides.

IT IS FURTHER ORDERED that if assumptions in setting these goals do not materialize, the goals may be revisited and modified in keeping with the facts known at such time.

IT IS FURTHER ORDERED that if by the next IRP filing, the respective Companies do not propose in their Plans reasonable alternatives to Staff's recommendations regarding the set asides, the Commission shall reconsider Staff's recommendations regarding long-term set asides to be implemented by the year 2009.

IT IS FURTHER ORDERED that each utility shall develop a database of existing renewable energy resources within its service area within six months from the effective date of this Decision; these inventories

³⁶ In the case of AEPCO, projects undertaken by member cooperatives can be counted toward the goal.

1 shall be revised annually and submitted to Staff each year as part of
2 the historical data filings required under the IRP rules.

3 IT IS FURTHER ORDERED that each utility shall prepare a three
4 year renewable resource action plan as part of its filing requirements
5 for an action plan under the Commission's IRP rules, starting with the
6 plans to be submitted by December 31, 1995.

7 IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson
8 Electric Power Company, Arizona Electric Power Cooperative, and
9 Citizens Utilities Company shall include in their next IRPs (to be
10 filed by December 31, 1995) explicit discussions of their research and
11 development plans and activities regarding renewables, including
12 descriptions of projects undertaken and costs of those projects.

13 IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson
14 Electric Power Company, Arizona Electric Power Cooperative, and
15 Citizens Utilities Company are hereby authorized to recover the
16 prudent costs of renewable resources within limits on the cost per kw
17 to be determined in future rate cases after Commission consideration
18 of utility cost estimates and proposals for cost recovery; the
19 criteria for determining the limits on costs shall include: estimates
20 of costs from engineering studies or field experience; the costs of
21 other (alternative) renewable technologies; the degree to which
22 commercialization of the technology has progressed; and the likelihood
23 that the proposed technology can be cost effective in the future (if
24 not currently cost effective)³⁷.

27 ³⁷ The proposed technology must reasonable be expected to
28 become cost effective as soon a practical, but in no event longer
than 15 years from the date the utility requests recovery.

1 IT IS FURTHER ORDERED that the Commission's policy stated in
2 Decision No. 57589 concerning the provision of information on
3 photovoltaics to potential line extension customers in remote areas,
4 based on Staff guidelines, is hereby continued.

5 — IT IS FURTHER ORDERED that proposals that renewable capacity may
6 be put into rate base and earn a return shall be considered in rate
7 cases.

8 IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson
9 Electric Power Company, Arizona Electric Power Cooperative, and
10 Citizens Utilities Company, may consider Green Pricing Programs and
11 may discuss Green Pricing Programs in their next IRP filings.

12 IT IS FURTHER ORDERED that any utility that wishes to engage in
13 supply or demand side bidding shall inform Staff of all requests for
14 bids at least 45 days prior to issuing the request and submit to Staff
15 a complete report on the bids, the utility's evaluation of the bids,
16 and the utility's selection of the winner(s) no more than 30 days
17 after selecting winning bids.

18 IT IS FURTHER ORDERED that Staff shall continue to participate in
19 Southwest Regional Transmission Association meetings on a regular
20 basis to keep informed of transmission planning issues.

21 IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson
22 Electric Power Company, Arizona Electric Power Cooperative, and
23 Citizens Utilities Company shall include in Plans or DSM reports
24 explicit analyses of the changes in their transmission and
25 distribution plans and associated savings attributable to DSM programs
26 if they wish to take credit for such transmission and distribution
27 savings.

1 IT IS FURTHER ORDERED that our decision to decline to adopt
2 standards regarding Exempt Wholesale Generators, in Decision No. 58424
3 (October 14, 1993), is hereby reaffirmed.

4 IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson
5 Electric Power Company, Arizona Electric Power Cooperative, and
6 Citizens Utilities Company shall submit values for capacity payments
7 to qualifying facilities over 100 kw for Staff review and approval
8 using the principles underlying the values in Staff Report Table 4,
9 page E-52, or such other principles as Staff the Companies may agree
10 to, within six months from the effective date of this Decision.

11 IT IS FURTHER ORDERED that the values in the Staff Table (or
12 Staff updates of these values) for capacity payments for purchases
13 from qualifying facilities over 100 kw shall be used if the utility
14 does not comply with the above paragraph.

15 IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson
16 Electric Power Company, Arizona Electric Power Cooperative, and
17 Citizens Utilities Company shall include in their filings maximum
18 payments for energy from QFs over 100 kw reflecting avoided fuel and
19 variable operating and maintenance costs, considering system
20 conditions, and the characteristics of QF power. These maximum
21 payments may be adjusted from time to time and may be reduced in the
22 course of individual contract negotiations.

23 IT IS FURTHER ORDERED that after Staff has determined that
24 Arizona Electric Power Cooperative's buyback rates for QFs over 100 kw
25 are in compliance (or that the Staff values should be used), Arizona
26 Electric Power Cooperative shall file jointly with each of its Arizona
27 member cooperatives appropriate buyback rates that will be paid by the
28 member cooperatives to QFs over 100 kw.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall revise their buyback rates regularly.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall increase their collection of end use load data, obtain commercial and industrial energy sales data by Standard Industrial Classification (SIC) category, collate that information with data on commercial and industrial customers such as number of employees in each SIC category, furnish Staff with a copy of the data to enable Staff to conduct independent analyses, and that Arizona Public Service Company, Tucson Electric Power Company, Arizona Electric Power Cooperative, and Citizens Utilities Company shall include the data described above in their annual IRP data filings.

IT IS FURTHER ORDERED that future IRP Plans shall include the following:

- ♦ the Plan shall have a comprehensive, self-explanatory load and resources table summarizing the utility's Plan;
- ♦ the Plan shall have an easy-to-read, brief executive summary that will inform the public about the utility's Plan and the load and resources table should be included in the executive summary. The executive summary can be provided to people requesting copies of the Plan instead of copying voluminous technical information that is of little value to individuals interested in a non-technical report;
- ♦ voluminous computer output is discouraged; it is usually incomprehensible, it needs interpretation, and it wastes paper;
- ♦ the Plan shall be in the form of a narrative leading the reader to logical conclusions and supported by tables, graphs, charts, etc;
- ♦ the Plan shall be indexed to indicate where the filing requirements can be found (see APS' Plan for an example);

- ♦ terms shall be defined as they are used by the utility; for example, different utilities use the term "forced outage rate" differently and it is not always clear whether demand includes or excludes sales for resale; and
- ♦ the Companies shall strive for consistency in data and assumptions throughout their Plans.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

David White
CHAIRMAN

[Signature]
COMMISSIONER

Dele H. Morgan
COMMISSIONER

IN WITNESS WHEREOF, I, JAMES MATTHEWS, Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 1 day of June, 1994.

James Matthews
JAMES MATTHEWS
EXECUTIVE SECRETARY

DISSENT _____
BSC

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